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ENERGY
COMMISSION

Agricultural Electricity Rates in California

CONSULTANT REPORT

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Executive Summary

Senate Bill 282 (Kelley 1999) directs the California Energy Commission to send a report to the State Legislature on agricultural electricity usage in California. The report is to analyze daily and seasonal usage patterns, compare agricultural rates among utilities in the Western U.S., examine the effects of restructuring on agriculture, and analyze strategies for reducing electricity costs incurred by agricultural customers. This report addresses those issues, with an emphasis on going-forward policies and strategies that affect agriculture. Due to the turmoil in California's electricity industry, the economic analysis of rates and energy costs can not be done in a timely fashion that is useful to the Legislature. However, the analytic tools developed here can be used to assess different policy options once some semblance of stability has returned to the industry. During this crisis, the state can consider the proposals made here to mitigate the impacts on agriculture.

California's agricultural sector represents a significant part of the state's economy, responsible for approximately 8 percent of gross state product (GSP). Agricultural production is dependent on access to water, either from surface supplies (e.g., the State Water Project), or pumped from underground aquifers. Moving water around–to irrigate fields, pump groundwater, water stock, or as part of food processing–requires energy. Ninety percent of electricity used by agriculture is associated with water use. As a result, energy can represent a significant portion of agricultural production costs.

For agriculture, energy costs are rising rapidly now and could have an even more significant impact this coming summer. Natural gas costs that have increased ten-fold from last winter and the recent rolling outages are now impacting these products:

- Dairy farmers with outages that force them to dump milk;
- Citrus growers fighting frost with wind machines and field heaters; and
- Greenhouse operators in the state's important nursery and floral industries who must supplement heating in their facilities.

This summer, state policy, as embodied in the CALFED and related processes, likely will reduce surface water supplies available to agriculture, and encouraging greater agricultural use of groundwater. As a result, California agriculture is experiencing intensifying cost pressures which could serve to limit grower operations, or drive some farmers out-of-business entirely.

This report describes the relationship between California agriculture and energy use, and provides possible strategies policy makers and growers can adopt to reduce agricultural energy demand and costs. Key recommendations are as follows:

- *Many measures to reduce and shift energy use are available to growers and water suppliers, but several key impediments stand in the way of their widespread adoption.* For example, water pumping and delivery systems' efficiencies can be improved in several ways. Because energy use can be readily rescheduled with adequate notice, agriculture is well positioned to participate in interruptible load programs. Water districts can store and draw from different sources with energy costs in mind. However, agricultural customers face problems in getting adequate information about these options. Investment risks appear to be higher in this sector than other business sectors. And regulatory and legal considerations preclude some attractive choices.
- *State policymakers need to improve coordination between resource management decisions*. Given the close relationship between agricultural water and energy use, policies developed by the Air Resources Board, Public Utilities Commission, State Water Resources Control Board, among others, should be managed comprehensively. For example, increased reliance on agricultural groundwater pumping to address water supply scarcity must be developed in tandem with policies that deal with the associated increases in agricultural energy demand.
- *State energy and environmental policies–including rate setting, load management, and air quality programs–must provide consistent encouragement to agriculture to invest in cost-effective energy and water demand strategies*. For example, growers should be offered long-term electricity rates that properly reflect the costs associated with the timing of energy use. Likewise, load management and "interruptible" programs sponsored by the Independent System Operator or others should enable agriculture to finance the infrastructure necessary to both reduce and shift energy use to lower-cost periods. And air quality policies should reflect a long-term investment

in reducing agricultural-related emissions without harming agricultural profitability.

Agricultural electricity usage is highly dependent on the commodity being produced. Dairy operations require about the same amount of energy year-round. Row crops require intensive irrigation and attendant pumping during the hottest months. The seasonal loads often can be shifted to periods of lower system demand to some extent, but to reduce economic consequences, these shifts must be well anticipated by farmers. This report compares costs for farmers for selected crops with varying pumping depths and in different locations using the recent rates increase effective June, 2001, as well rates in effect in 2000. The cost comparisons are illustrative, however, as that they cannot fully capture the wide variety of energy-use patterns that are evident in the agricultural industry. The models prepared for making these comparisons are available to make useful comparisons if the Commission wishes analyze agricultural energy use patterns in the future.

The report also describes the evolution of California's regulatory energy policies regarding agriculture. PG&E has proposed in its 1999 General Rate Case to merge smaller agricultural customers with other commercial customers as a means of mitigating concerns over revenue allocation methods. SCE has proposed in its Post Transition Rate Design filing to greatly increase its monthly demand charge component while reducing the energy usage rate. Both of these proceedings are now on hold during the current crisis, with no indication of resolution.

Finally, the report discusses the recent behavior in California's power market, and what the future range of power purchase rates might be. Due to the uncertainty in the markets at the moment, rates could fall within a very wide range, and seasonal and hourly pricing could vary substantially.

Chapter 1 of this report covers proposed on-farm energy management strategies, and state policies that could best encourage these strategies. Chapter 2 examines on-farm electricity use patterns and costs for various crops and dairies. Chapter 3 discusses California's electricity ratemaking process, and bill comparisons with other neighboring states' utilities. Chapter 4 discusses potential responses by growers to the changing electricity market, including demand management and fuel switching.

Chapter 1

Available Policy Options to Manage Agricultural Energy Costs

1.1 Introduction

Agriculture is responsible for about 8% of California's gross state product (GSP).[1] Representing only 3% of the nation's farmland, California growers produce *half* of the nation's agricultural product by value. Yet the state's agricultural sector's economic well-being is threatened by the ongoing electricity crisis.

In 1992, the California Energy Commission issued a report to the Legislature, as directed by Assembly Bill (AB) 2236, that examined the combined impact on California agriculture of the then-ongoing drought and the change in how agricultural rates were set by the state's two largest investor-owned utilities (IOUs)–Pacific Gas and Electric (PG&E) and Southern California Edison (SCE) companies.[2] The AB 2236 report found that the likely response to the challenges facing the agricultural sector was to shift production from low-value to high-value crops (e.g., alfalfa to tomatoes). Even with higher costs, the agricultural economy was robust and these high-value crops were able to absorb those costs.

Today, agricultural commodity prices have been driven down by worldwide competition, greatly reducing the net returns to all California agricultural operations. Growers and food processors are now more vulnerable to increased costs, such as higher electricity rates, that cannot be passed along in higher prices. Significant reductions in profitability could lead to bankruptcies, and concomitant reductions in agricultural output. The recent spate of cooperative failures (e.g., Tri Valley and Farmers' Rice) and processing plant closures are examples of the current weakness in the agricultural economy.

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[1] Harold O. Carter and George Goldman, "The Measure of California Agriculture: Its Impact on the State Economy," Revised Edition (Oakland, California: University of California, Division of Agriculture and Natural Resources, December, 1998).

[2] Ricardo Amon et al., "Increasing Agricultural Electricity Rates: Analysis of Economic Implications and Alternatives," P400-92-030, Report to the Legislature - AB2236 (Sacramento, California: California Energy Commission, June, 1992).

Given the seriousness of the current situation, this report presents a set of policy recommendations that could be adopted by the state to assist agriculture in addressing the energy crisis. The recommendations fall into two general categories:

- Measures that can be adopted by individual farmers and agricultural water suppliers to reduce their energy costs; and
- Measures that can be implemented by state agencies to facilitate the strategies that farmers and districts could use to reduce their costs.

These measures are discussed separately in this report. The latter set of recommendations range from policies affecting rate setting to those which would influence statewide water supply management. Many of these measures can be implemented by the individual agencies without any additional action by the Legislature.

This report reviews the findings from the AB 2236 report, and updates this analysis to reflect existing conditions.[3] The AB 2236 report provided estimates of the economic impacts on different crops in different regions of the combination of water supply scarcity and increased energy costs, presented a list of potential actions to mitigate these costs, and identified the challenges associated with implementing these actions. Although many of the policy recommendations and issues contained in the 1992 report remain viable and available for implementation, electric industry deregulation and ongoing threats to power reliability present new issues that call for targeted solutions. In addition, future research is suggested as a means to the further policy objectives identified in this report.

1.2 Economic Implications of Higher Electricity Rates to Agricultural Customers in California

Agricultural electricity demands and associated costs are driven by the need to move surface water and pump groundwater. More than 90 percent of the electricity used by agricultural customers in California is used to pump water.[4] The state is home to almost 500 agricultural water supply districts, many of which use pumps to convey part or all of their water to farms. In addition, individual fields often utilize farmer-owned booster pumps. Only a few of these districts–Turlock Irrigation District (ID), Modesto ID, Imperial ID are the largest–generate their own power.

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[3] Much of this discussion is taken directly from the AB 2236 report.

[4] Amon, op. cit.

When surface water supplies are low, electricity use increases, as more groundwater is pumped. Simultaneously, water scarcity tends to be associated with reduced agricultural profitability, as growers reduce the amount of land cultivated in the face of higher production costs. For example, from 1988 to 1994, surface water deliveries to agriculture were sharply reduced due to the continuing drought. The state established large-scale water trading mechanisms—the "State Drought Water Banks"—in 1991, 1992 and 1994 to deal with water shortages. Estimates of drought-related reductions in farm sales in 1991 alone range from $200 to $600 million,[5] with losses increasing in 1992 and 1994.

Surface water supplies continue to be tight. Implementation of the Central Valley Project Improvement Act, combined with the listing of several endangered and threatened species in the Bay-Delta watershed, have resulted in lower surface water deliveries to agriculture even after the drought ended in 1994, and during one of the wettest multi-year periods on record. CALFED[6] is now proposing to increase reliance on agricultural "conjunctive use"–a water management approach that requires yet more groundwater pumping during dry years by growers.[7] These factors will almost certainly lead to an increase in average agricultural pumping loads in the future, even as cultivated acreage falls.

With increasing reliance on groundwater and competition in national and worldwide agricultural commodity markets, higher and/or volatile electricity rates reduce the viability of agricultural production and processing in California. Agriculture operations already have relatively low returns.[8] And competitive markets prevent growers from passing on higher production costs.

The magnitude of the economic implications of higher and/or volatile electricity rates on agricultural customers will depend on several factors. In cases in which electricity costs represent a large percentage of the crop's per-acre value, the impact will be more significant. For example, a 25% increase on a farm operation where energy

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[5] Amon, op. cit.

[6] CALFED is a program by state and federal agencies working on the management of the Bay-Delta Estuary.

[7] CALFED, "Record of Decision," August 28, 2000.

[8] The University of California Agricultural Cooperative Extension estimates the average return to farm operations is 8% annually. In comparison, the return on the S&P 500 over the last 50 years has been about 12%.

costs are 4% of total costs would act to reduce average returns from 8% to 7%, whereas a similar increase in which energy costs represent 20% of the total would reduce returns to 4%.

How farmers will be affected is largely dependent on two factors:

<u>(1) Crop Type:</u> While the profits of agricultural customers producing low-value crops, such as alfalfa, rice, cotton and other field crops, will be reduced to a greater extent than from higher-value crops, such as fruits and vegetables, due to higher electricity rates, growers for all commodities now face more competition and have less resiliency than in the early 1990s.

A direct economic implication of higher electricity rates on agricultural customers is a reduction in farm profit. Farm profits result from the revenue generated by the crop produced minus the costs incurred. Higher electricity costs will have to be absorbed by agricultural customers who are unable to increase crop prices to consumers.

A combination of factors, including reduced surface water deliveries, increases in electricity rates, and added out-of-state competition in many commodities that used to be dominated by California producers, are acting to accelerate California's ongoing shift from low- to high-value crops. The shift to high-value crops has served to increase the investment needed to participate in California farming: high-value crops, such as citrus and nuts, tend to require substantial multi-year investments (e.g., planting orchards). The need to recover capital as well as operating costs adds substantial risk to farm operations, associated returns must be greater, and lenders tend to charge higher rates. As a result, the margins for California farmers have been reduced, and the financial cushion once provided by high-value crops has been eroded.

Current market conditions, including higher electricity costs, reduced power reliability, the economic slowdown, and lower than normal water precipitation, makes agriculture particularly vulnerable to economic dislocation. The impact of high energy costs combined with potential commodity losses from power interruptions could significantly weaken the economic viability of some farms and food processors, and drive others out-of-business entirely.

<u>(2) Water Source:</u> Agricultural customers who depend solely on groundwater sources will be the most affected by higher electricity rates.

Higher electricity rates will particularly reduce the profits of agricultural customers who are especially dependent on groundwater, and who have limited access to surface water. As groundwater depths increase due to overdraft (i.e., over-pumping) or as a result of drought, more energy will be required to bring the same volume of water to the surface. Likewise, growers who are required to shift from surface to groundwater sources due to supply shortages or regulatory decisions will experience a sharp increase in their energy costs. At least in the short term, increased groundwater pumping combined with higher electricity rates will reduce farm profits. Agricultural customers growing low-value crops in surface water deficit areas–the west side of the Sacramento and San Joaquin Valleys and Kern County–will be the most affected by higher electricity rates. Field crop acreage declined 17% from 1988 to 1998, in part in response to higher water application costs.[9]

The current proposal in the CALFED Bay-Delta Program Record of Decision issued August 28, 2000 to increase reliance on agricultural conjunctive-use management would act to exacerbate agriculture's exposure to risk in today's uncertain water supply and energy markets. The Sierra snowpack is already in deficit. Reduced surface water deliveries coupled with an unreliable power supply at high costs would adversely affect the agricultural sector. Under proposed policies, farmers will be required to further increase their pumping during drought years, which also coincides with reduced hydropower availability, leading to higher electricity market prices. As a result, agriculture will be hit with both higher energy usage and rates. *The State appears to not be consciously managing its rapidly evolving water and energy policies in a coherent manner.*

1.3 Options in the Field to Address Power Costs, Reliability and Load Management Issues

Various strategies are available to farmers, irrigation districts, food processors and storage facilities to reduce electricity costs, be more efficient and possibly generate their own power, as well as implement load management practices. However, the costs and benefits of individual alternatives are site-specific. These various options are discussed below.

1.3.1 Physical Investment

- *Improved water management and reduced water use can reduce electricity expenditures.* Electricity costs can be reduced by decreasing the volume of water

[9] See Section 2.2 for further discussion.

pumped. High efficiency irrigation and irrigation scheduling can also provide increased crop yields.

- *Electricity costs can be reduced by increasing pumping plant efficiency.* Pumping plant efficiency declines over time as the pump incurs wear. Repair of inefficient pumping plants can reduce electricity use by as much as 50 percent. Use of energy efficient motors and proper pump and motor selection can assure lower lifetime electricity costs.

- *Reducing pumping pressures can reduce electricity costs.* Reducing sprinkler discharge pressures, friction losses in irrigation water distribution systems and other pressure reductions, can provide moderate electricity savings. Economical pipe sizing, proper use of valves and pressure regulators, and maintenance of filters are also important for improved efficiency.

- *Increasing pump size can enhance the ability to pump during off-peak periods.* To take advantage of low off-peak rates, farmers must be able to meet their irrigation needs in a shorter time period. This requires lifting more water per hour. Larger pumps will achieve this goal. However, high utility connection or demand charges that are insensitive to time of use can act to discourage this type of investment. If these demand charges inappropriately collect costs on non-coincident loads during off-peak hours, they will adversely affect the broader state energy management objective to reduce peak usage.

  As another example, irrigation districts that operate many automated (with simple timers) tile drainage pumps, or the farmers within the districts who own such pumps, can install timers on tile drain pumps. Tile drainage pumps are typically small – 2.5 – 10 HP each. However, there are thousands of such pumps in California. In most cases, it would not be detrimental to any farming or hydraulic operation if these pumps were controlled so that they only pump during off-peak hours. This would be a very simple conversion, only requiring the installation of a special timer on each pump.

- *Districts in the San Joaquin Valley offer good potential for innovative power management by potentially turning off their deep wells during peak power usage times.* Several irrigation districts rely on groundwater pumping for a significant percentage of their water supply. There is, however, a need to invest in hardware, software and technical staff to implement the following practices:

- Drilling new wells to make up for the shortfall that would occur due to not pumping on-peak.
- Installing variable frequency drives on all pumps to prevent damage to the wells from frequent start/stop operation.
- Installing a remote monitoring and control (SCADA) system.
- Increasing reservoir capacity to store pumped water for usage during on-peak hours. Most districts own the land necessary for use as a reservoir.
- Installing new control hardware and inlets/outlets for the reservoir/canal connections.

An approximate cost to a district implementing this type of program would be:

• Drilling new wells and installing pumps:	$ 50,000 to 60,000 per well
• Installing VFD controllers on all pumps:	$25,000 per pump
• Building of a regulation reservoir:	$1 to $3 million
• SCADA system:	$800,000

The typical irrigation district may shift net load from peak hours by approximately three to ten megawatts through these investments.

1.3.2 Energy Management Choices

- *Using least-cost electricity rate schedules can reduce electricity costs.* Electric utilities offer a range of electric rate schedules that provide cost incentives for operating at times other than the summer on-peak period. Even if the utilities reduce the number of schedules, farmers will have several choices. Implementing operational changes to take advantage of off-peak or other low-cost rates can reduce electricity costs substantially.

- *Participating in load-management and interruptible load programs can reduce electricity costs.* An essential component in enhancing the functioning of the restructured power market is increasing demand responsiveness. Agricultural customers generally require less service reliability than residential, commercial and industrial customers, as borne out by utility value of service studies. Thus, given the appropriate opportunity and concomitant support, growers and water agencies are more likely to participate in interruptible load programs than other customers at the same level of compensation are. Likewise, an added benefit comes with agricultural load curtailment: agricultural pumping loads are higher in drought years, coinciding with reduced electricity supplies (i.e., hydropower). That is, loads can be reduced precisely for the customers who have a disproportionate impact on the supply shortage.

1.3.3 Distributed Generation and Alternative Fuel Sources

- *Use of internal combustion engines can reduce irrigation pumping costs.* For some agricultural customers, internal combustion engines are cost-competitive with electricity for irrigation pumping at current electricity and fuel prices. As electricity prices have risen, the number of pumping plants powered by internal combustion engines has also increased. On the other hand, lower reliability, higher maintenance costs, and the possibility of fuel spills can lower the attractiveness of diesel, natural gas or propane. Moreover, further penetration of internal combustion engine pumps may exacerbate regional air quality problems if not properly managed by the state and local agencies. Encouraging installation of new, clean pumping technologies through such programs as the Carl Moyer Memorial Air Quality Standards Attainment Program, managed by the Air Resources Board, is a key means of mitigating this issue.

- *On-site generation using environmentally acceptable natural gas turbines and/or methane gas production.* Irrigation districts may consider siting back-up generation capacity by installing natural gas turbines that comply with air quality standards. Food processors and dairy farms also have the option to install new generation biogas production reactors that can be used to produce methane gas and meet on-site power needs, both for cogeneration and to supply the electric utility grid.

1.3.4 Water Management Strategies

- *Replenishing groundwater supplies during periods of above normal rainfall can serve to decrease electricity use by reducing pumping lifts.* In a viscous cycle, groundwater pumping can lower water tables, resulting in the need for increased electricity use for pumping. However, replenishing groundwater reservoirs with available surface water serves to raises groundwater levels, helping to maintain a reliable water source while reducing electricity expense. It is important to note, though, that agriculture will bear the burden of conjunctive-use management to enhance statewide water supplies, since agricultural operations have the best access to the largest rechargeable aquifer capacity. Farmers and agricultural water districts should receive compensation for increased pumping costs from other water users who benefit from these programs.

- *On-demand water delivery by water districts can reduce electricity use for groundwater pumping.* Irrigation district delivery schedules can act to limit farm-level adoption of water-conserving technologies. For example, drip irrigation systems require small quantities of water delivered daily while many irrigation districts provide water in large quantities delivered at intervals of one to two weeks. As a result, agricultural customers installing drip irrigation systems must pump groundwater. On-demand surface water deliveries would allow growers to adopt high-efficiency irrigation technologies and thereby reducing groundwater pumping.

- *Water supply agencies can time surface water deliveries in the mid- and late summer to reduce groundwater pumping.* With flat or fixed electricity rates, farmers saw little difference as to whether they pumped in May or August, especially if both months fell into the "summer" period of the rate schedule. The restructured power market has now made time of use much more relevant to agricultural pumping. Water agencies can help farmers manage their energy costs by making deliveries later in the summer when these prices are higher, and encouraging farmers to pump earlier in the year. For example, the California State Water Project (SWP) and federal Central Valley Project (CVP) could hold San Luis Reservoir higher later into the summer, and then draw it down deeper. This change may reduce water quality, but proposals by Metropolitan Water District to swap water with the Friant Water Users Association and to build a new connection to the San Felipe Division likely would serve to mitigate concerns about urban water quality.

  Other options to shift water sources during on-peak hours are available as well. For example, three irrigation districts–Banta Carbona ID, West Stanislaus ID, and Patterson ID, located between Los Banos and Tracy–are in a unique situation. They pump most of their water uphill from the San Joaquin River, through a series of canals and lift pumps. However, all three districts have some capability of also receiving water from the uphill end of their canals via a connection to the Delta-Mendota Canal (DMC). It may be possible to arrange a transfer of water rights for the purpose of on-peak load shifting, so that these districts can receive most of their water needs during those hours by gravity from the DMC, thereby allowing them to shut-off many of their pumps. Implementation would also require that bigger connections be installed to the DMC, as well as new control schemes be installed for canal control.

- *Water districts can provide communal holding ponds to allow for off-peak pumping with on-demand deliveries.* Building a holding pond for a small farm operation is cost-prohibitive, although larger operations often find them cost effective. However, a water district can provide the necessary economies of scale by facilitating the pooling of operations among several farmers. Alternatively, the water district can build storage capacity for its own operations. In addition, districts can install or enlarge existing buffer reservoirs at the heads of canals that are fed by large pumping plants on the California Aqueduct. Several irrigation districts in Kings and Kern Counties have large pumping plants on the banks of the California Aqueduct that lift water into reservoirs located several hundred feet uphill. Those reservoirs supply canals that are owned by the irrigation districts. If the pumping plants have sufficient capacity, it may be possible to pump all of the required water during off-peak hours and store water for on-peak needs in large buffer reservoirs. In some cases, buffer reservoirs would need to be enlarged; in other cases they would need to be installed.

- *Water districts can participate in water transfers that enhance surface water supplies in water-deficient areas.* Water districts should not only look to buy for their customers, but also should try to sell excess short-term supplies. Having an adequately functioning market requires willing participation by both buyers and sellers. Even water transfers from regions with shallower groundwater to deeper groundwater can be beneficial under certain conditions. In addition, the State Water Resources Control Board (SWRCB), U.S. Bureau of Reclamation (USBR), and California Department of Water Resources (CDWR) need to continue moving toward removing barriers to these trades.

  One example of how a district can mitigate water shortages through transfers is the Westlands Water District. Westlands has received its full Central Valley Project contract deliveries only twice since the 1987-94 drought despite unusually wet years. As a result, Westlands has supplemented its supply by purchasing between 95,000 and 220,000 acre-feet each year since 1987. These purchases have reduced potential groundwater pumping and kept land in production that would have otherwise been fallowed.

- *Change operation of drainage pumps in the Sacramento Valley.* The Sacramento Valley has many Reclamation Districts whose primary purpose is to maintain drainage canals and the pumping plants that lift drainage water out of the districts and into the rivers (e.g., Reclamation District 108 and Sutter Mutual Water Company). Some drainage canals are quite large and may be capable of storing large volumes of water without overflowing and damaging adjacent farmland. To shift power loads may require a simple change in controls at the pump, or it may also require the installation of additional pumps that can pump extra water during off-peak hours.

- *On-farm participation in conjunction with irrigation district participation.* In some districts there is access to hardware that may facilitate implementation of large TOU operations. Specifically, areas of some districts, such as in Westlands Water District, have pipelined distribution systems. On-farm, most fields are irrigated using drip or microspray and each field has a booster pump. It may be possible to coordinate pumping activities so that both the field and district pumping are stopped together. This has some control advantages, and limits some of the need for large reservoirs. However, checks must be made to be certain that there is sufficient capacity in both district and on-farm systems to provide the needed water during off-peak hours. There are several districts in Kern County that have a few very large farms. These may provide the best opportunity for examining these options, as only a few people would need to be involved for a rather significant trial.

1.4 Barriers to Adoption of Effective Energy Management Strategies

Many technologies and management practices are available to reduce water and electricity demand. However, adoption rates for these strategies have been low. There are several barriers impede agricultural customers' investments in energy efficient and water conserving technologies and management practices.

- *Growers and lenders alike perceived greater risks to investments as a result of unstable resource and commodity markets.* Under the current rate setting process, electricity rate structures can change dramatically within a few years, as evidenced in the most recent rate design applications by both PG&E[10] and SCE.[11] As a result, agricultural customers are reluctant to make investments because determining economic feasibility is subject to major regulatory uncertainties. Allowing agricultural customers to remain on a stable electricity rate long enough to recover their capital investment–energy and demand charges could still have periodic increases, but their relationship to each other would remain the same–would reduce economic uncertainty. Over time, improved rate stability would contribute to increased investment in electricity and water conserving technologies.

- *Energy and water management infrastructure tends to have high capital costs and long payback periods.* Adoption of energy efficient and water conserving technologies and management practices can be very expensive–installing drip irrigation on one 100-acre orchard can cost from $75,000 to $150,000–and these

[10] GRC Phase II, A.99-03-014.

[11] PTRD, A.00-01-009.

investments often have payback periods of seven to ten years. Lowering the cost of capital investments through utility company rebates or access to low-interest rate financing would result in increased investments in electricity and water conserving technologies. With the State planning to rely more extensively on conjunctive-use management under the current CALFED proposal, coordination of investment to achieve both energy and water savings is necessary.

- *There are different economic incentives to invest in resource management infrastructure between owner-operators and tenant-farmers.* This can significantly affect the willingness to invest in capital intensive technologies. Establishing a flood or furrow irrigation system only requires moving earth and laying pipe. On the other hand, installing a low-pressure drip system can cost hundreds of dollars per acre. An owner retains all of the returns from such investment, and control over the equipment. A tenant may have to share some of the return with the landlord in higher rents, and may have to leave behind any in-ground irrigation installations. Changes in lease agreements or targeting tenants for technology investment subsidies could address this issue.

- *There is a lack of coordination between growers, water districts and relevant public sector agencies.* Implementing policies that will control agricultural energy costs, reduce water demands, and meet statewide environmental objectives requires that the various state and federal agencies that regulate and manage water, energy and environmental resources coordinate their policy objectives and choices. While some coordination occurs at the staff level among these agencies, virtually no meaningful discussion is ongoing among policy-makers. In fact, government policies are often developed that conflict with each other. Examples of such conflicts include:
    - The CALFED Record of Decision calls for adding 500,000 to 1,000,000 acre-feet of additional underground storage by 2007 to be used by agriculture (p. 46). However, the CALFED EIR/EIS hardly considers how such a program would increase pumping loads in drought years, which in turn would increase statewide electricity loads, wholesale power prices, urban air pollution from power generation and rural air pollution from diesel and natural gas pumping, and the volatility of farm cashflows.[12] In contrast, previous testimony before the SWRCB

[12] CALFED Bay-Delta Program, "Final Programmatic EIR/EIS," July 2000.

found that air emissions from electricity generation alone could rise substantially with increased agricultural pumping.[13] In addition, the recently issued Draft EIR on the proposed divestiture of PG&E's hydropower assets found that statewide electricity prices varied significantly with water conditions. Increased agricultural pumping during droughts would only serve to expand this volatility.

- Agricultural water pump engines that are less than 175 horsepower are exempt from air quality regulations under federal law. These pumps have been identified as a significant source of air emissions, particularly in the Central Valley. The California Public Utilities Commission (CPUC), on the other hand, has adopted rates, including standby and bypass tariffs, that encourage agricultural customers to switch to diesel or natural gas-fueled pump engines due to the relatively high cost of electricity. The Carl Moyer Memorial Air Quality Attainment Program, managed by the Air Resources Board (ARB), will encourage farmers and water agencies to switch to lower-emission motive power sources for groundwater pumping through grants and loans. However, the ARB's analysis identifies existing barriers in state electricity rate policy to expanded use of electricity—the cleanest motive source—for pumping. Given that the state cannot directly regulate air emissions from these sources, but it does not appear ready to give incentives to switch to electricity, the ARB may want to consider a greater emphasis on encouraging the installation of cleaner (diesel or natural gas) pumping engines.

Appendix I discusses farm-level impediments to adoption of water and energy-conservation measures that exist in California and throughout the West. The findings in Appendix I are based on the US Department of Agriculture's 1998 Farm and Ranch Irrigation Survey as part of the Census of Agriculture. Large changes in energy prices can affect the incentives that farmers have for adopting conservation measures, which should be considered by the Commission and the state in setting policy.

[13] Richard McCann, David Mitchell, and Lon House, "Impact of Bay-Delta Water Quality Standards on California's Electric Utility Costs," (Sacramento, California: Presented before the State Water Resources Control Board on behalf of the Association of California Water Agencies, October 7, 1994).

1.5 Policy Proposals to the State Legislature and Agencies

Many of the on-farm and water district strategies discussed above require encouragement, legitimization, or investment from the state and federal governments to occur. The following actions by various agencies would help achieve lower energy costs, improve reliability, and reduce environmental impacts.

The State should require its resource and management agencies to consider the full range of impacts on water supply and quality, air quality, energy usage and prices, and the agricultural economy in all relevant proceedings. The various agencies should keep each other fully informed about these proceedings, and should be willing to provide expert analytic support on those topics on which the lead agency may not be fully knowledgeable.

1.5.1 Electricity Regulation and Management

(1) The CPUC should develop an agricultural rate design approach that explicitly ensures rate stability to reduce uncertainty to farmers, and thereby improves these customers' ability to recover infrastructure investments. The proposed PG&E class merger with commercial customers is one such measure.

(2) The CPUC should ensure that demand charges accurately reflect only fixed costs, and that these charges are set appropriately for peak versus off-peak periods. Cost studies must be conducted over a long enough period to accurately capture costs which truly vary with usage. Identifying the cause and timing of peak demand on local circuits also must be done carefully so as not to penalize farmers who are acting to avoid peak demand periods. In addition, the CPUC should consider the impact of demand charges on incentives to switch to fossil-fueled pump engines, and the commensurate impacts on regional air quality.

(3) The CPUC should evaluate how it can expand participation by agricultural customers in time-of-use schedules. Such actions may include lowering the size threshold for participating in such schedules. As part of this effort, the utilities must be given the correct incentives to distribute interval meters to agricultural customers.

(4) The CPUC and California Independent System Operator (ISO) should develop policies that encourage agricultural customers to enroll in load management and

interruptible programs. For example, an existing requirement to participate in these programs is the ability to aggregate a substantial amount of loads (e.g., 250 kilowatts in the Energy Commission's proposed AB 970 program, and one megawatt in the ISO's Summer 2001 Demand Relief Program). Other opportunities to offer interruptible loads to the Independent System Operator, the utilities or even another state agency may arise before this summer. However, agricultural customers are prohibited from aggregating their loads through master-metering, as the utilities claim that such aggregation leads to undercollection of revenues. These opportunities can only be realized if the existing prohibition on master-metering of agricultural loads for a single customer is revoked.

1.5.2 Water Resources Management

(5) CALFED and state energy regulatory agencies should coordinate their agricultural water and energy management policies to ensure that the state achieves all of its resource management objectives. For example, relevant agencies should ensure that proposals for conjunctive use management do not exacerbate state energy problems CALFED should ensure that farmers and agricultural water districts receive compensation for increased pumping costs from other water users who benefit from these programs.

(6) CALFED and state energy regulatory agencies should coordinate programs that encourage on-farm and district-level water and energy management investments so as to maximize benefits and minimize costs.

(7) CALFED should evaluate and consider the energy management benefits of allowing more flexible operation of the San Luis Reservoir by installing a new connection to the San Felipe Division of the State Water Project. Greater operational flexibility would allow for increased summertime surface water deliveries in the San Joaquin Valley, which in turn would reduce groundwater pumping during peak load periods.

(8) CDWR should communicate with the state's agricultural water districts on how to best implement on-demand water scheduling. In addition, these districts should be encouraged to make surface water deliveries during the mid-summer period

rather than the late-spring as now often occurs.

(9) CALFED and the SWRCB should develop guidelines to encourage short-term water transfers that can reduce groundwater pumping, particularly during the summer peak-load periods.

1.5.3 Research Agenda

(10) The Energy Commission should further develop an evaluation tool that allows farmers and agricultural service advisors to assess the costs and benefits of different irrigation and rate schedule configurations. The basic framework this tool has been developed as part of this report. The evaluation tool could be made available through the Internet on the Energy Commission web site. In addition, the evaluation tool could be further refined to be used in statewide water management policy evaluations.

Chapter 2

Agricultural Energy Use and Costs in California

2.1 California's Agricultural Industry Current Situation in the Energy Crisis

California agriculture leads the nation in farm production. It is a prime export engine for the state's economy, and generates $73 billion in annual economic activity.[1] Yet, California agriculture has faced recent difficulties. Agricultural output peaked in 1997 at $27.5 billion, but fell 3% by 1999 while the rest of the state economy was booming.[2] Net farm income fell even more dramatically, from $6.25 billion in 1997 to $4.99 billion in 1999, or more than 20%. While statistics are not yet available for 2000, agriculture showed signs of stress. Commodity prices continued to fall, and several large grower cooperatives, most notably Tri-Valley, suffered severe financial setbacks due to market conditions.

In addition, California farmers are facing significant water supply cutbacks for 2001. The California State Water Project (SWP) is forecasting deliveries of only 35% of contract entitlements, and the federal Central Valley Project (CVP) is planning similar reductions. Growers incur a disproportionate share of these cuts relative to urban water customers due to project policies to ensure urban water supply reliability. CALFED has explicitly decided in its recent Record of Decision to rely on "conjunctive use management" to improve water supply reliability.[3] Conjunctive use means that agriculture is to rely more heavily on groundwater pumping during dry conditions and to store water runoff in aquifers during wet conditions.

Farmers are left with few alternatives in this situation. Electricity costs are a significant share of farm costs.[4] Farmers can either pump groundwater or leave the land fallow. The latter option means that they will produce substantially less income. Given that the vast majority of farmers rely on electricity to power their pumps, the pumping looks less and less attractive.

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[1] Harold O. Carter and George Goldman, *The Measure of California Agriculture: Its Impact on the State Economy*, Revised Edition, 1998 (Oakland, California: Division of Agriculture and Natural Resources, University of California, December, 1998).

[2] California Agricultural Statistics Service, *California Agricultural Statistics*, *1998-99: Agricultural Overview* (Sacramento, California: California Department of Food and Agriculture, 2000).

[3] CALFED Bay-Delta Program, *Programmatic Record of Decision* (Sacramento, California: California Resources Agency, California Environmental Protection Agency, U.S. Environmental Protection Agency, U.S. Department of the Interior, U.S. Department of Agriculture, U.S. Department of Commerce, U.S. Army Corps of Engineers, August 28, 2000).

[4] Ricardo Amon et al., *Increasing Agricultural Electricity Rates: Analysis of Economic Implications and Alternatives*, P400-92-030, Report to the Legislature - AB2236 (Sacramento, California: California Energy Commission, June, 1992).

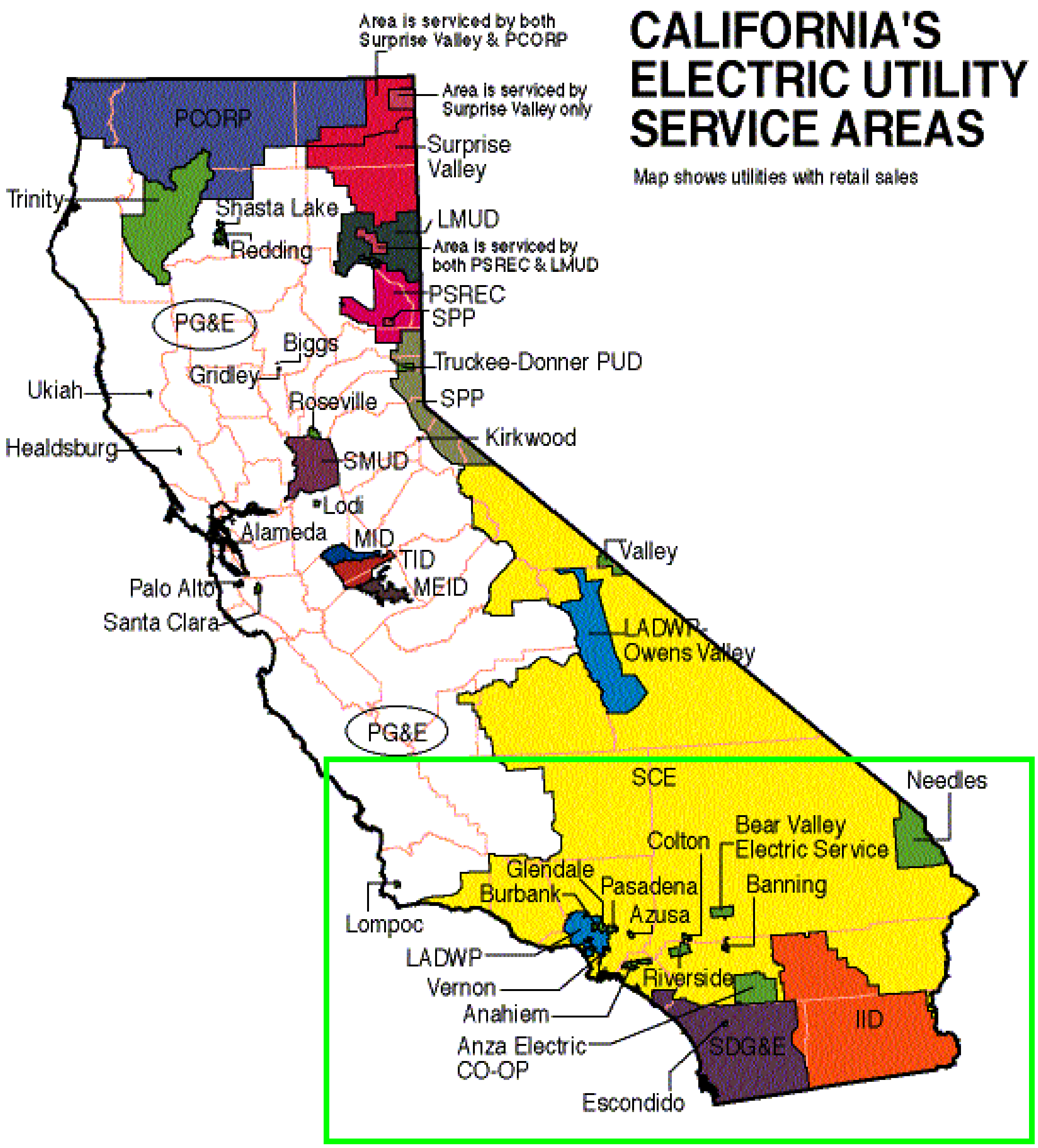
Increased fallowing will lead to reduced employment opportunities for farmworkers and less business for local agricultural suppliers.

Finally, the state released at least an additional 100,000 acre-feet of SWP water supply in December and January to generate power during the electricity crisis. A comparison of the net inflow data to Oroville Reservoir over the September to January period shows an almost unprecedented decrease of 183,000 acre-feet. Such reductions historically have been associated only with flood control requirements, yet Oroville was already at sufficiently low levels in August. While the added generation from Oroville was necessary to maintain the electricity system, the loss of stored water will come almost entirely out of agriculture's water supply. In essence, the state has imposed a cost on farmers this summer.

2.1.1 Overview of Agricultural Energy Use in California

California's electricity is supplied by a number of generators - some located in state and some located out of state. The electricity is distributed by another set of business entities, some of whom are generators of electricity. The major distributors of electricity to California agriculture are Pacific Gas and Electric (PG&E) and Southern California Edison (SCE). Other distribution companies serve California agricultural producers, but these companies serve rather specific geographic areas. Figure 2-1.1 shows the regional service areas of all distribution companies serving California.

Figure 2-1.1



Each utility distribution company's share of farm gate value and harvested irrigated acreage is shown in Table 2.1.1

Table 2.1.1

Utility Distribution Company Shares of Farm Gate Value and Harvested Irrigated Acres		
Utility Distribution Company	**Percent of Farm Gate Value**	**Percent of Harvested Acres**
Pacific Gas & Electric	59%	66%
Southern California Edison	24%	18%
San Diego Gas & Electric	4%	1%
Others	13%	15%

Each of the utility distribution companies provides electricity to agriculture as well as other economic sectors. Electricity consumption by sector and utility distribution company supplies to the sectors are shown in Table 2.1.2. The table focuses on average annual gigawatt-hours (GWh) consumption figures for two time periods - 1980-1982 and 1996-1998.

Table 2.1.2

Electricity Consumption by Sector and Utility Distribution Company - Averages of 1980-1982 and 1996-1998 Years

	Residential		Commercial		Industrial		Agriculture		Other		Total
	GWh/yr	% row	GWh/yr	% row	GWh/yr	% row	GWh/yr	% row	GWh/yr	% row	GWh/yr
Pacific Gas & Electric											
1980 - 1982	21,391	32%	18,144	27%	17,339	26%	5,766	9%	3,988	6%	66,628
1996 - 1998	28,772	30%	32,041	34%	23,325	24%	5,604	6%	5,606	6%	95,348
Change	7,381		13,897		5,986		-162		1,618		28,720
Change %	35%		,77%		35%		-3%		41%		43%
Southern California Edison											
1980 - 1982	17,355	29%	17,726	29%	18,630	31%	3,495	6%	3,035	5%	60,241
1996 - 1998	25,252	29%	29,359	34%	22,480	26%	5,157	6%	5,267	6%	87,515
Change	7,897		11,633		3,850		1,662		2,232		27,274
Change %	46%		66%		21%		48%		74%		45%
Other Utility Distribution Companies											
1980 - 1982	13,340	37%	13,862	38%	5,480	15%	726	2%	2,753	8%	36,161
1996 - 1998	18,791	35%	22,623	43%	6,265	12%	951	2%	4,397	8%	53,027
Change	5,451		8,761		785		225		1,644		16,866
Change %	41%		63%		14%		31%		60%		47%
Total All Companies											
1980-1982	52,086	32%	49,732	31%	41,449	25%	9,987	6%	9,776	6%	163030
1996-1998	72,815	31%	84,023	36%	52,070	22%	11,712	5%	15,270	6%	235890
Change	20,729		34,291		10,621		1,725		5,494		72860
Change %	40%		69%		26%		17%		56%		45%
Annual Rate of Growth	2%		3%		1%		1%		3%		2%

As shown, the average annual energy consumed by California has risen from 163,030 to 235,890 GWh over the 19-year period considered. The average annual electricity consumed by agriculture has risen from 9,987 to 11,712 GWh over the same period. Even though agriculture's consumption increased, the agriculture sector's percent of the total energy consumed by all sectors in California dropped from six to five percent during this time. California agriculture has never been a large part of electricity consumption in the state - agriculture lags far behind the Residential sector (31 percent of the total), the Commercial sector (36 percent of the total), and the Industrial sector (22 percent of the total).

The energy supplied agriculture by PG&E has gone down by 3 percent while the energy supplied by SCE has increased by 48 percent over the same period. PG&E and SCE now supply about the same amount of energy to the agricultural sector as measured by the Energy Commission.[5]

The annual rates of growth in average annual consumption by the different sectors show interesting differences. The annual rates of growth of consumption, during the 19-year period, for the different sectors are:

Residential: two percent

Commercial: three percent

Industrial: one percent

Agriculture: one percent

Other: three percent

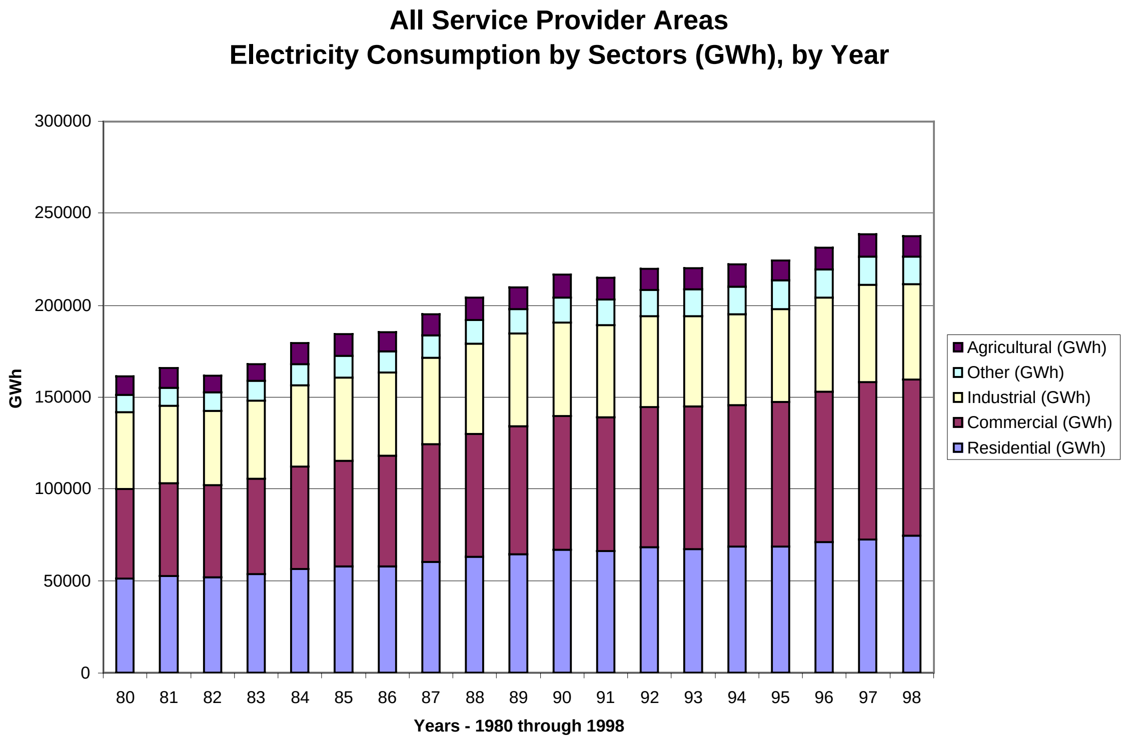
Entire state: two percent

Detailed annual information about the amounts of electricity delivered by each utility distribution company to each sector is shown in Appendix II. Figures 2.1.2 through 2.1.5 follow and graphically illustrate some of the data in the appendix tables.

Figure 2.1.2 shows annual electricity consumption by sector during the 1980 - 1998 period. Annual increases in electricity consumption in the Residential, Other and Agricultural sectors were stable over the 18-year period. Larger annual increases in electricity consumption by the Commercial and Industrial sectors occurred between 1983 and the early 1990s than occurred after 1992.

[5] The utilities show substantially different “sales” figures to agricultural customers than the Energy Commission. This largely due to the Energy Commission identifying agricultural load by U.S. Department of Commerce Standard Industrial Classification (SIC) code, while the utilities identify these customers by which tariff the customers use to receive electricity.

Figure 2.1.2



Figures 2.1.3 and 2.1.4 show annual energy consumption by sector for PG&E and SCE, respectively. Residential and commercial usage rises steadily is both cases, but industrial consumption exhibits significant cycles, particularly in the SCE area. Agriculture is a relatively small, but constant portion of demand in both areas.

Figure 2.1.3

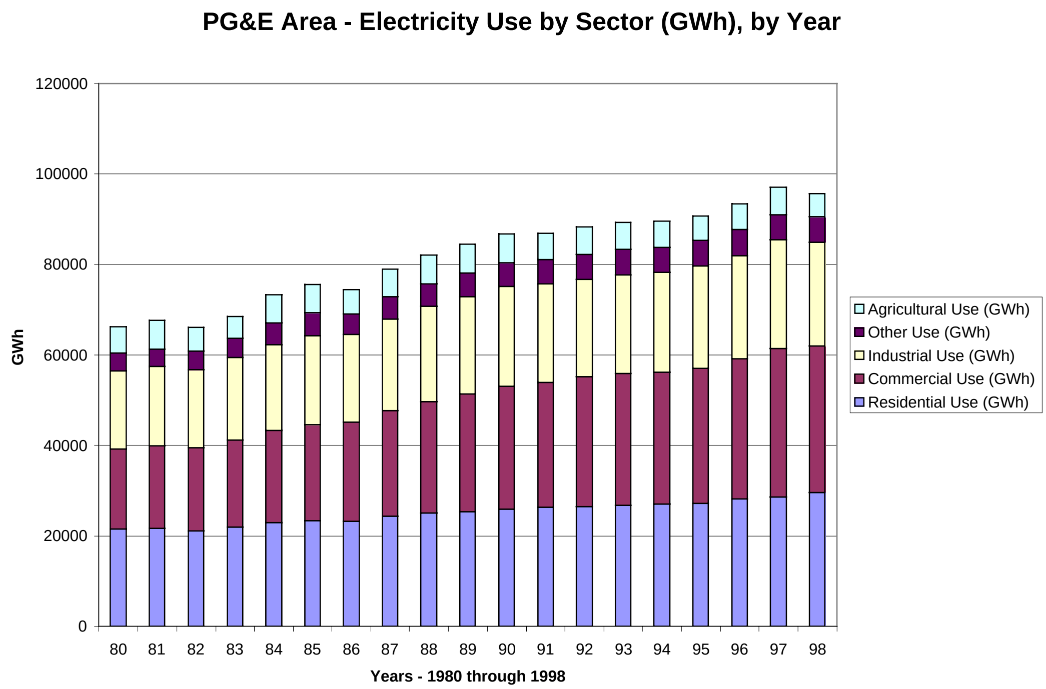


Figure 2.1.4

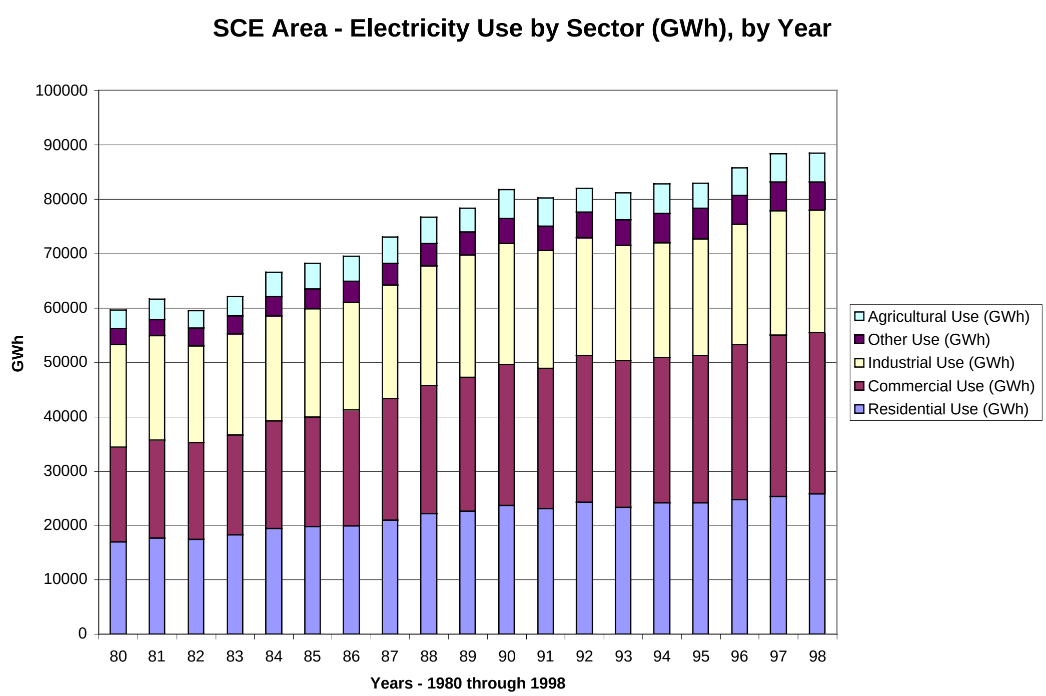
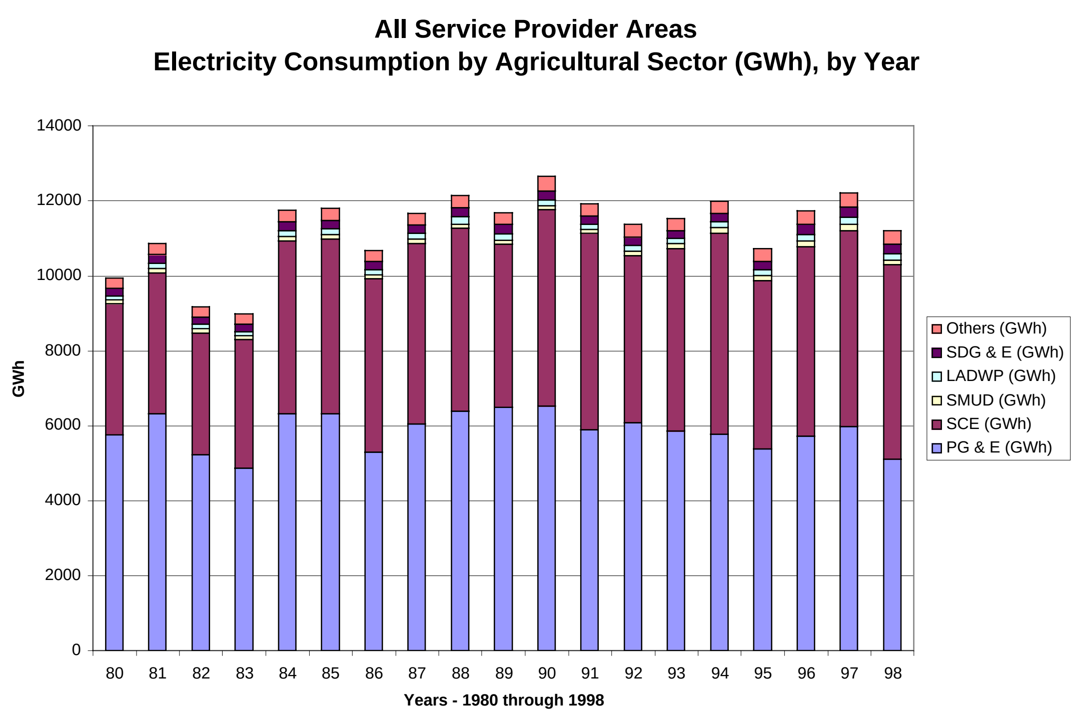


Figure 2.1.5 illustrates electricity consumption by the agricultural sector in all service provider areas. The predominance of PG&E and SCE in serving agriculture is evident. The figure also shows the increased amounts of electricity provided agriculture by SCE, beginning in the mid-1980s. The reasonably steady decline in agricultural usage provided by PG&E is shown. By far the largest proportion of the increase in energy provided by SCE between the early 1980s and the late 1990s had occurred by the mid-1980s. Variations in consumption in both service areas occurred around the longer-term trend lines. The variations in electricity use resulted from changes over time in supplies of surface water, as well as changes in crop profitability.

Figure 2.1.5



2.1.2 Uses of Agricultural Electricity by Geographic Area

According to Energy Commission publication P400-92-030, also known as the "AB2236 Report", a significant proportion of all electricity used by agricultural customers is used to pump groundwater.[6] Table 2.1.3 illustrates the significance of using electricity to pump groundwater as compared with other uses.

The table shows the following:

- Almost 90 percent of the electricity used by agriculture in California is used to pump groundwater
- Just over 60 percent of the electricity used by agriculture in California is used in the San Joaquin Valley to pump water
- The dairy sector uses about 9 percent of the electricity used by agriculture in California
- Slightly more than half of the CA dairy sector's electricity use occurs in the San Joaquin Valley

Table 2.1.3

Regional Uses and End Uses of Agricultural Electricity, by Percent of Total

	End Uses				
Region	Water	Dairy	Green-houses	Frost	Row Totals
San Joaquin Valley	61.6	4.7	0.3	0.3	66.9
Central Coast	5.7	0.5	0.8	0	7
South Coast	4.8	0.7	0.5	0	6
Sacramento Valley	4.6	0.4	0	0	5
Southern Desert	0.5	2.4	0	0.1	3
North Coast	1.4	0.4	0.5	0	2.3
Sierra/Northern Inland	1.9	0.1	0	0	2
Other*	7.8	0	0	0	7.8
Column Totals	88.3	9.2	2.1	0.4	100

*: balancing

Source: Table compiled from Table 1 and Table 2 in CEC Report P400-92-030

The "water use" column in the above table was further broken down in the AB2236 Report into types of crops irrigated. However, the breakdown was not done on a regional basis. Across California, the irrigation of field crops was said to account for about 70 percent of the electricity used to pump water (about 62 percent all electricity). Irrigation of fruit and nut crops accounted for about 20 percent (about 18 percent of all electricity), and irrigation of vegetable crops accounted for the balance.

[6] Amon, et al. (1992), op. cit.

Given the contents of Table 2.1.3, the initial impact of changing electrical rate schedules (or the lack of available energy) will be especially significant for producers of field crops. Field crop production accounts for a large proportion of total electrical energy consumed during a typical year. A second factor is of importance to field crop producers - the proportion of total crop production expenses that is electrical energy. Table 2.1.4 is reproduced from the AB2236 Report below. The table shows electricity costs as a percent of production costs for representative crops. The table incorporates average costs for typical California farms. Individual producers could expect either higher or lower costs, depending on geographic location, scale of operations, etc.

Table 2.1.4

Electricity Costs as a Percentage of Production Costs

Low Value Crops	Percent of Production Costs	High Value Crops	Percent of Production Costs
Alfalfa	30.0 to 35.0	Citrus	10.0 to 15.0
Rice	25.0 to 27.0	Peaches	7.0 to 10.0
Cotton	20.0 to 25.0	Almonds	7.0 to 10.0
Barley	23.0 to 26.0	Grapes	6.0 to 9.0
Sugar Beets	20.0 to 22.0	Broccoli	4.0 to 5.0
Processing Tomatoes	8.5 to 11.0	Lettuce	3.0 to 4.0

Production costs include cash cost for cultural practices or pre-harvest costs. Water costs as a percent of production costs for selected field crops are shown in Department of Water Resources, *The California Water Plan Update*, Bulletin 160-98.
Source: CEC Report P400-92-030, Table 3 (p. 16)

Electricity costs are a much higher percentage of production costs for field crops than for fruit, nut and vegetable crops. Given the general economic conditions (depressed product prices, increasing input costs, and increasing regulation compliance burdens) facing California agricultural producers, increased electricity costs will pressure cash flow levels, further erode profit margins, and increase financing uncertainty. In the longer term, increases in electricity rates above current levels could hasten:

- California's shift from lower value to higher value crops
- Fallowing land that would have been used for irrigated field crops
- Pressures to convert land to non-agricultural uses (e.g., housing)

2.1.3 Agricultural Electricity Use and Cost

Total electricity expense has accounted for about five percent of intermediate cost outlays (total farm business expenses) and about 20 percent of the cost of manufactured inputs during the 1994 - 1998 period. Table 2.1.5 provides the numbers used to calculate these percentages.

Table 2.1.5
Intermediate Consumption Outlays* by Year

	1994 (X$1,000)	1995 (X$1,000)	1996 (X$1,000)	1997 (X$1,000)	1998 (X$1,000)	5-year average
Farm Origin**	2,919,554	3,239,225	3,235,070	3,611,210	3,474,225	
Manufactured Inputs						
Fertilizers & lime	665,739	773,345	803,525	906,165	785,456	
Pesticides	790,202	899,558	991,914	1,109,170	1,075,788	
Petroleum fuel and oils	373,144	385,587	470,037	491,464	425,646	
Electricity	508,093	567,577	693,407	554,201	513,062	
Total of Manufactured Inputs	2,337,178	2,626,067	2,958,883	3,061,000	2,799,952	
Other intermediate expenses***	5,778,126	6,400,745	6,137,286	7,135,145	6,742,963	
Total intermediate consumption outlays	11,034,858	12,266,037	12,331,239	13,807,355	13,017,140	
Electricity as % of Manufactured Inputs	21.7%	21.6%	23.4%	18.1%	18.3%	20.6%
Elec. as % of inter. consump. outlays	4.6%	4.6%	5.6%	4.0%	3.9%	4.6%

*: variable costs of all production not including direct gov't payments, motor vehicle fees, and property taxes
**: includes feed purchased, livestock and poultry purchased, and seed purchased
***: includes repair and maintenance of capital items, machine hire and custom work, marketing, storage, and transportation, contract labor, and miscellaneous
Data from CDFA 1999 Resource Directory, page 34.

Total farm business expenses (total intermediate consumption outlays) increased steadily from 1994 through 1997, and then declined in 1998. Expenditures for each of the manufactured inputs, except electricity, followed this pattern. Electricity expenses were less in 1997 than in 1996. The 1998 decline in spending for all manufactured inputs resulted from the decline in harvested acreage of most California field crops (in particular, cotton). California harvested field crop acreage (major crops) declined from about 3.7 million acres in 1996 to about 3.2 million acres in 1998. (See Appendix II for field crop acreage data). Agricultural electricity rates were frozen from 1996 through 2000. Therefore, changing rate structures should not have impacted total expenditures on electricity during this time.

If average electricity costs increase 25 percent from present levels, and all other costs remain constant, the increase could result in about a one percent increase in annual farm business expenses incurred by all California producers. However, when a 25 percent increase is applied to the production costs for representative irrigated crops, cost increases are much more significant.

2.2 Patterns of Agricultural Energy Use at the Aggregated Level

Agricultural customers have somewhat predictable energy uses patterns in the aggregate, but forecasters and rate analysts do not always recognize and act on those patterns. The most important pattern is the year-to-year and seasonal patterns driven by water availability and application. A dry year that reduces surface water deliveries leads to higher groundwater pumping loads. A wet year with substantial water availability decreases electric pumping demand. Hot, dry summers that correspond with the growing season lead to higher pumping loads every year, with variation driven largely by surface water availability. Marsh and Archibald (1992) indicated that during normal water years more than 50 percent of San Joaquin Valley agricultural water supplies are pumped from groundwater sources. It was also noted that in critically dry years, the percentage could increase to 70 percent.

The second type of pattern is for weekly and daily usage. These patterns vary substantially by type of agricultural operation and the ability of those operations to shift loads in response to changes in electricity rates and in water availability. For example, many irrigators now pump water at night or on weekends to take advantage of lower off-peak prices. On the other hand, dairy operations largely are locked into twice-a-day milkings at set times.

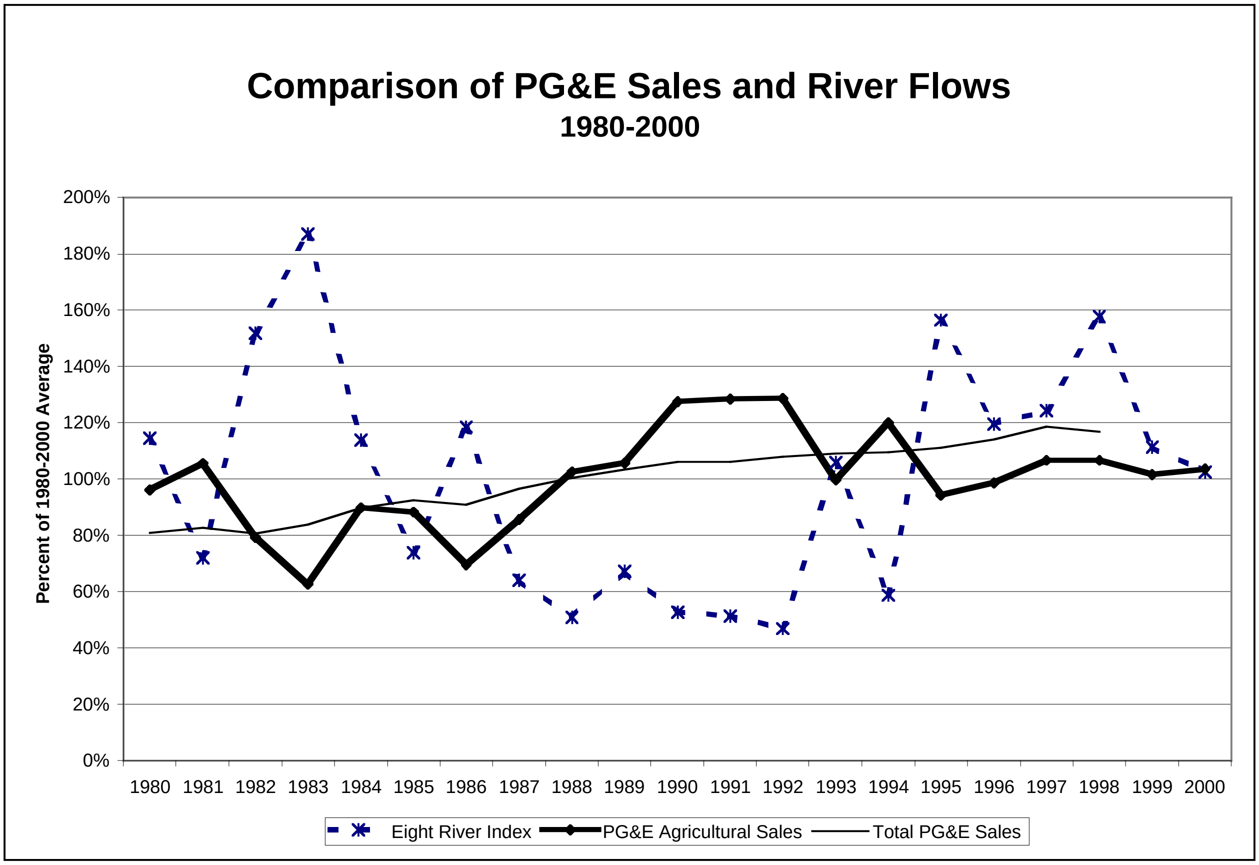
2.2.1 The Relationship of Agricultural Energy Use and Water Supply

Agricultural energy use patterns are intimately linked with on-farm water use: energy is the tail on the water dog. Growers principally rely on electricity to move water around – either to pump groundwater, or to move surface supplies to crops or storage facilities. As a result, agricultural energy use is to a large extent determined by the availability of water.

Figure 2.2.1 illustrates the strength of this relationship by comparing PG&E's agricultural sales for 1980 to 2000 the "Eight River Index" (ERI), which measures water availability in the state's largest rivers system. In wet years, when surface water supplies are ample, agriculture uses less electricity. Alternatively, during dry years, when growers must rely more heavily on groundwater, electricity use rises. The correlation coefficient between sales and the ERI is -0.70 during that period.[7] Figure 2.2.1 shows, in contrast, that during the period PG&E's system wide sales had little relationship to water supply availability. Because of this linkage between energy and water, although the number of agricultural customers barely changes from year-to-year, the class' demand for energy can substantially vary between and within seasons depending on water supply conditions.

[7]A correlation coefficient of -1.0 describes a perfectly negative linear relationship between the two variables, i.e., that sales would rise in direct proportion to a decrease in water availability.

Figure 2.2.1



An econometric model linking the agricultural energy demand in the PG&E service area to stream flows in the Central Valley shows how agricultural demand rises as water availability falls.[8] Table 2.2.1 shows how electricity demand changes relative to the long-run average for the Eight-River Index of 11.6 million acre-feet (MAF). Of particular note is how much demand increases in years listed as "critically dry." In such years, which occur after a succession of dry years, water project deliveries are cut dramatically and local water supplies are scarce. Groundwater pumping causes demand to rise rapidly. Critically dry years typically occur when the ERI falls below 6.4 MAF.

[8] The correlation coefficient between the Eight River Index and agricultural sales is –0.70. The log-log regression model used 1970 to 2000 PG&E recorded sales data:

*ln(PG&E Ag Sales) = 8.535 – 0.137*ln(Eight River Index) + 0.177*critically dry year – 0.262*flood &PIK years*

Adjusted R-squared = 0.60

A similar model was developed for SCE using 1980-1998 Energy Commission demand data. It showed an R-squared of 0.40.

Table 2.2.1
Effect of Eight River Index on Agricultural Demand

Eight-River Index (MAF)	PG&E GWH	PG&E %	SCE GWH	SCE %
4	1,387	38%	189	4%
5	1,235	34%	167	4%
6	1,115	31%	148	3%
7	261	7%	50	1%
8	190	5%	37	1%
9	129	4%	25	1%
10	75	2%	15	0%
11	27	1%	5	0%
11.6	0	0%	0	0%
12	(17)	0%	(3)	0%
13	(56)	-2%	(11)	0%
14	(93)	-3%	(18)	0%
15	(126)	-3%	(25)	-1%
16	(157)	-4%	(31)	-1%
17	(186)	-5%	(37)	-1%
18	(213)	-6%	(43)	-1%
19	(238)	-7%	(48)	-1%
20	(262)	-7%	(53)	-1%

Based on the demand forecast model shown here, agricultural electricity use will rise 8.9% this year above the forecasted energy demand developed by PG&E in its Rate Stabilization Plan Proceeding (A.00-11-038).[9] This means that agricultural energy bills will rise by at least 10% regardless of whether rates are increased since almost all of this increased usage will occur during the higher-priced summer period.

Southern California Edison's agricultural sector electricity use shows a similar negative relationship with surface water deliveries during the 13-year period from 1986 through 1998. The correlation between surface water deliveries (SWP and CVP) to the San Joaquin Valley and electricity use is -0.77.[10] The strong negative relationship existed, as long as surface water deliveries remained above about 4-million acre-feet. In years when surface water deliveries dropped to about 3-million acre-feet, growers reduced harvested acreage rather than to pump more ground water.

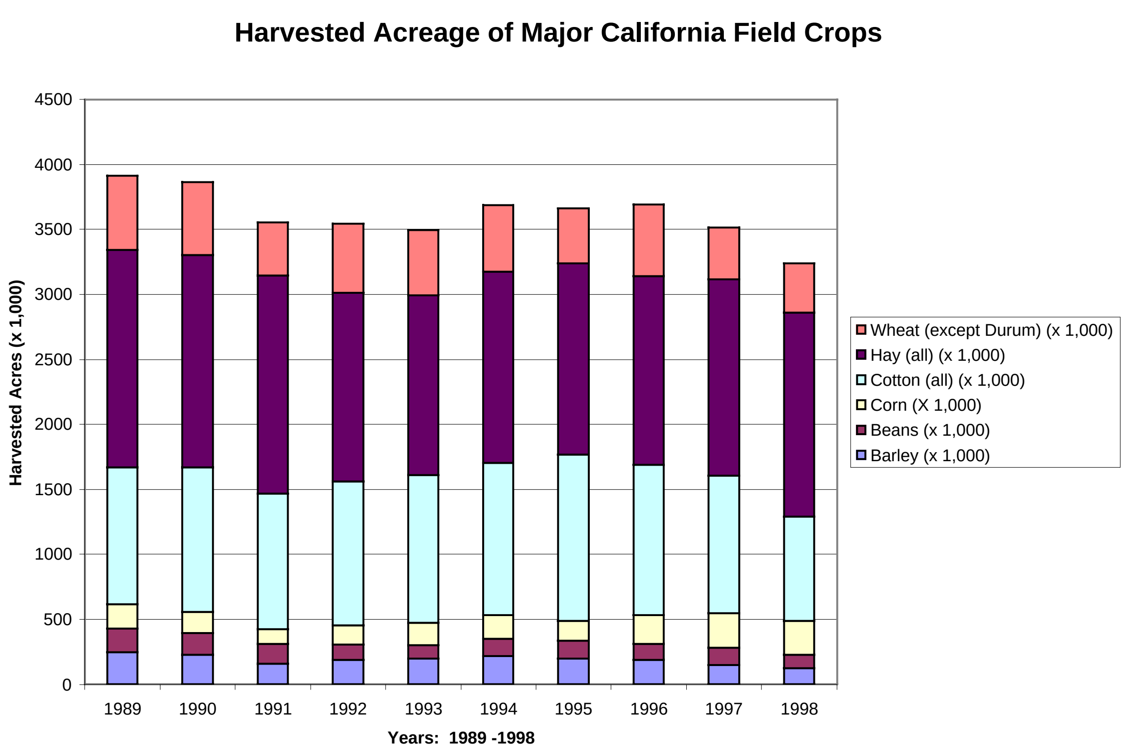
The impact of reduced surface water deliveries can have a broader impact on field crop acres, as is illustrated in Figure 2.2.2. In general, significantly reduced surface water deliveries in 1991 and 1992 resulted in a decrease in harvested field crop acres, as well as a change in the crop mix. In 1993, when surface water supplies had been restored, the general agricultural

[9] The forecasted Eight River Index for 2001 is 8.0 million acre-feet. This is about the same as the index in 1987 when the last extended drought began. PG&E's demand forecast is based on the average for the previous three years usage. The three-year average for the Eight River Index for 1998 to 2000 was 14.9, versus the long-run average of 11.6 for the 1906 to 2000 period.

[10] The data for 1991 and 1992 (low surface water delivery years) were omitted from this calculation.

economic conditions were not favorable enough to result in field crop acreage to be restored to previous levels. Harvested field crop acreage increased in 1994, even with low surface water deliveries, as more electricity was used to pump groundwater that year. Growers expected greater returns for crops than in previous years. Surface water supplies were restored to record levels in 1995, but harvested acres did not increase above 1994 levels, as growers reduced their use of groundwater that year. Harvested field crop acreage totals increased slightly in 1996, and then decreased in 1997 and 1998. The change in the field crop mix during the 1989-1995 showed a movement toward more highly valued field crops. Harvested cotton acreage increased during the 1989-1995 period by 222,000 acres, hay acreage decreased by 200,00 acres, and wheat acreage decreased by 145,000 acres. The total decrease in harvested field crop acreage through 1995 was about 250,000 acres. Field crop harvested acreage increased slightly in 1996 in response to almost record-level surface water deliveries and increased groundwater pumping. However, by 1998 decreased surface water supplies, coupled with less than favorable crop net margins, reduced field crop harvested acreage to about 3.24 million acres. This was 673,000 fewer acres--17.2 percent--than in 1989. Appendix II shows harvested acres by year for California field crops over the 1989-1998 period.

Figure 2.2.2



As noted in the AB2236 Report, "(h)igher electricity rates will compound the economic effects of surface water deficits as agricultural customers shift from surface to groundwater sources." However, overall economic considerations also enter producers' decisions to plant field crops. Declining crop prices combined with higher water-contract prices, as Central Valley Project contracts were renewed, and less reliable water project deliveries to squeeze field crop profits and reduce planted acreage.

2.2.2 Agricultural Load Profiles

A “load profile” is the hourly electric demand pattern for a particular class of customers over a specified period of time, such as a week or a year. Load profiles are used by the utilities and by direct access providers to schedule power purchases and to allocate energy purchase costs. The utilities have developed load profiles for smaller customers who do not have time-of-use hourly interval meters as a means of estimating how loads vary for these customers. The load profiles are estimated from a sample of the customer class and then extrapolated to all customers. For most customers, the statistical precision of those estimates is quite tight. For agriculture, however, the estimates’ precision is quite poor—the range of the confidence intervals for each hour often include loads equal to zero! For this reason, applying a single, cookie-cutter, load profile to all agricultural customers often gives a distorted view of their usage pattern.

The California Energy Users Cooperative (CEUC) serves 17 agricultural cooperatives. Of these customers, a substantial portion is made up of growers. The CEUC provided the Energy Commission’s consultants with the hourly-metered loads for its members who are growers for the period for July 1, 1999 to June 30, 2000. This data allows us to look at agricultural load profiles from an actual customer group.

Figures 2.2.3 and 2.2.4 show the annual load profiles, using a seven-day moving average to smooth the loads, for customers in the PG&E and SCE service areas, respectively. The load profiles are categorized by the size of demand in maximum kilowatts, separated into four categories commonly used by the utilities for rate-setting purposes. The rise in loads during the summer and the fall in mid-autumn is evident in all of the load categories. The PG&E loads tend to rise somewhat earlier in the year than for SCE, probably due to the larger amount of acreage in field crops that require pre-irrigation. The SCE loads remain higher later into the fall, reflecting the larger amount of acreage in citrus orchards. The SCE loads appear somewhat more erratic because there are fewer CEUC growers in that area, and a single grower has a greater influence on the average patterns shown here.

Figure 2.2.3

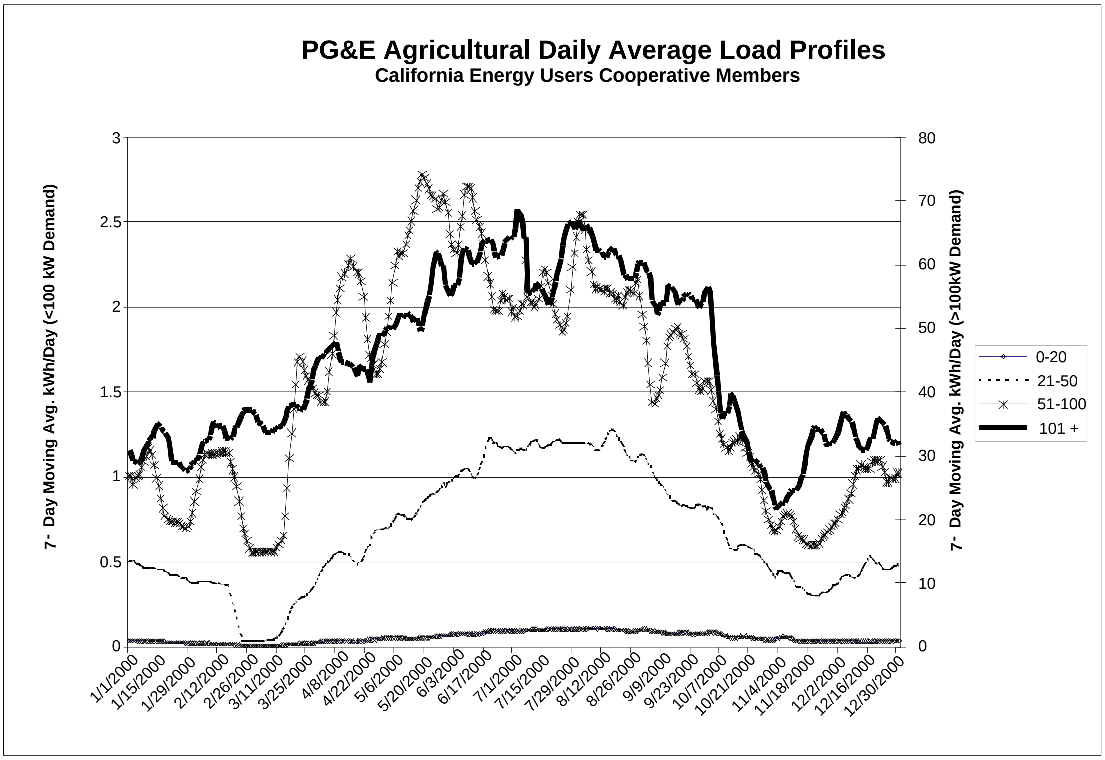
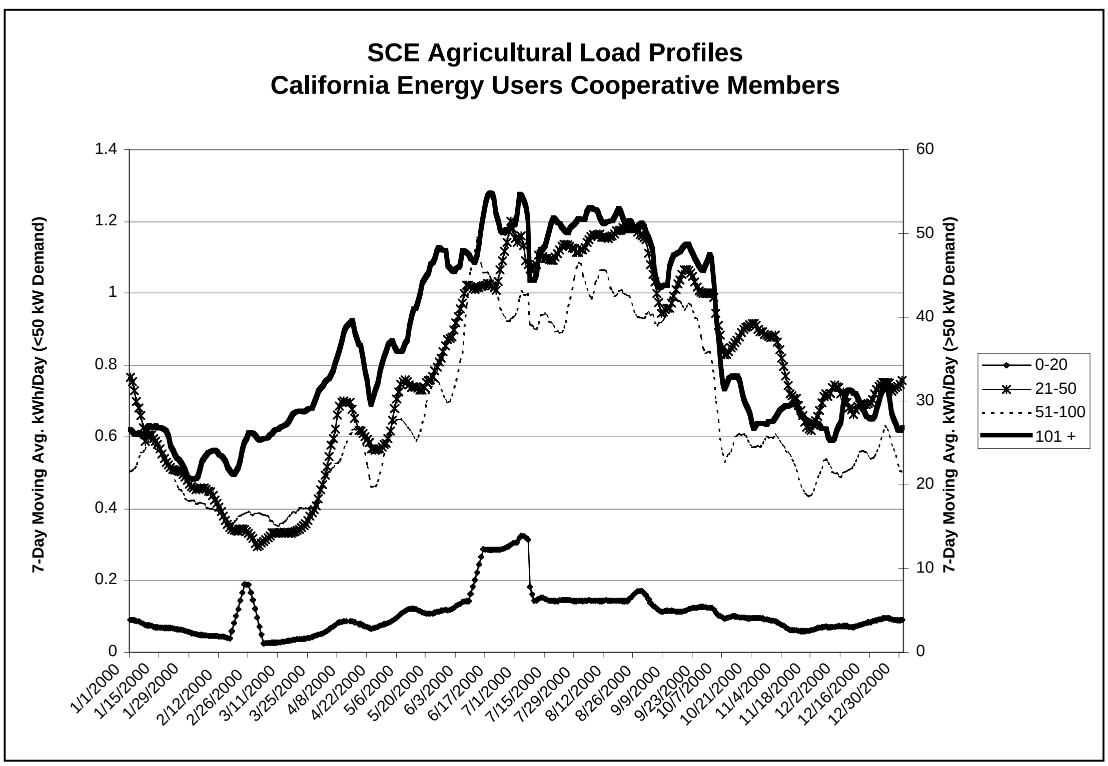


Figure 2.2.4



Figures 2.2.5 and 2.2.6 show the hourly loads over a single week in July. The load pattern is quite different from the system-wide load pattern in two ways. First, peak weekly loads tend to be on Saturday and Sunday as farmers try to irrigate during off-peak hours. The second is that the daily peaks, which vary substantially, tend to be during the morning hours rather than in the late afternoon. This reflects agronomic practices for irrigating earlier in the day. In general, growers appear to be using most of their electricity at hours other than the weekday peaks when power prices are highest and system resources are most strained.

Figure 2.2.5

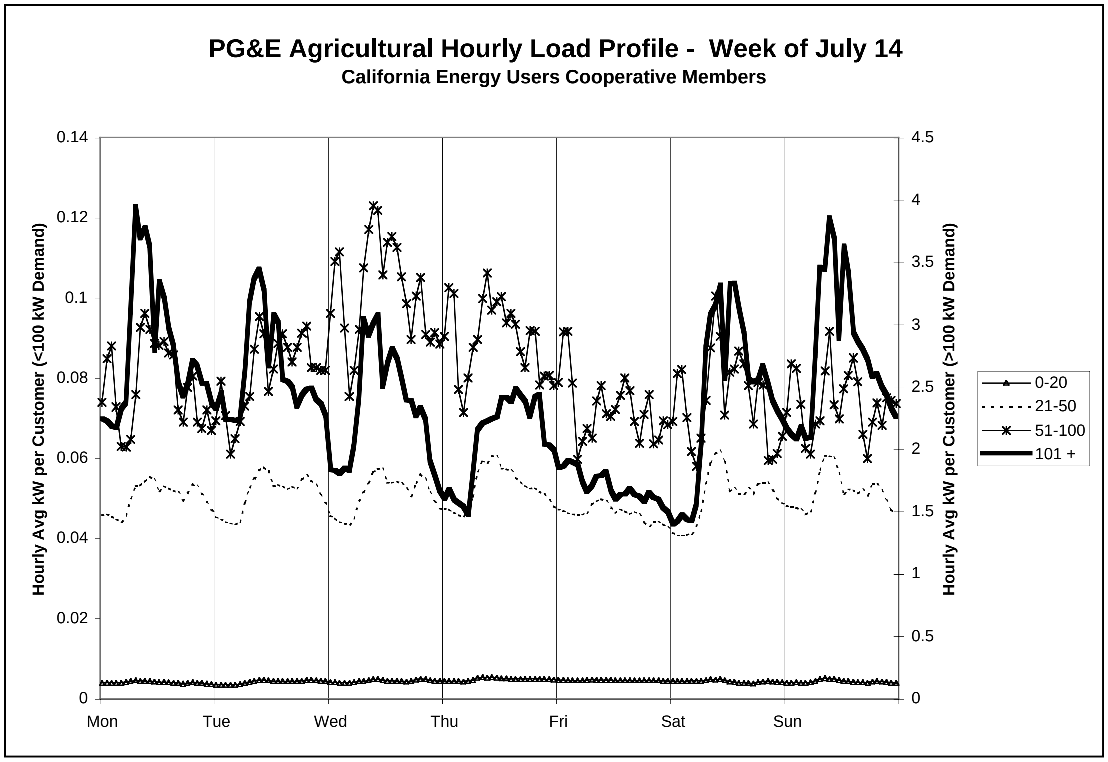
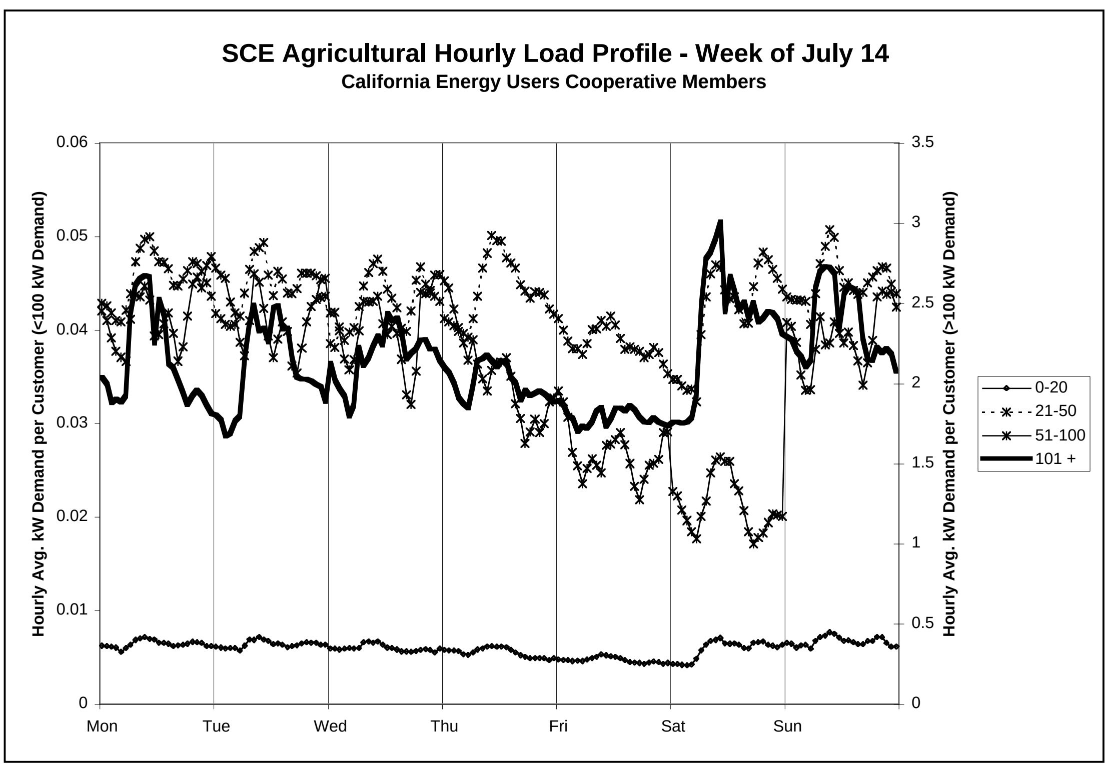


Figure 2.2.6



2.3 Agricultural Rates Used in Analyses

The agricultural rates used in the bill impact analyses in Sections 2.4 and 2.5 are based on those adopted by the California Public Utilities Commission and implemented in June 2001. Where rate comparisons are made with previous rates, the rate schedules in force before January 2000 have been used. The two tables below summarize the agricultural rates for SCE and PG&E, respectively.

Table 2.3.1 SCE Selected Agricultural Electric Power Rate Schedules, June 2001

Advice Letter 1545 - E May 22, 2001	Effective Date 6/3/01	PA-1 Summer	PA-1 Winter	TOU PA-B Summer	TOU PA-B Winter	TOU PA-4 Summer	TOU PA-4 Winter	TOU PA-5 Summer	TOU PA-5 Winter
Total Energy Charge									
Peak	$/kwh			0.17408		0.19369		0.13545	
Partial	$/kwh			0.09756	0.11003	0.11018	0.12484	0.07542	0.08422
Off-peak	$/kwh			0.06452	0.06452	0.06073	0.06073	0.06683	0.07320
Flat	$/kwh	0 12247	0.12247						
Generation									
Peak	$/kwh			0.17159		0.19120		0.13356	
Partial	$/kwh			0.09507	0.10754	0.10769	0.12235	0.07353	0.08233
Off-peak	$/kwh			0.06203	0.06203	0.05824	0.05824	0.06494	0.07131
Flat	$/kwh	0.11320	0.11320						
Transmission - Distribution & Various									
Peak	$/kwh			0.00249		0.00249		0.00189	
Partial	$/kwh			0.00249	0.00249	0.00249	0.00249	0.00189	0.00189
Off-peak	$/kwh			0.00249	0.00249	0.00249	0.00249	0.00189	0.00189
Flat	$/kwh	0.00927	0.00927						
Connected Load -Demand Charges									
Monthly	$/ kW	2.05	2.05	2.85	2.85	2.85	2.85	2.85	2.85
		PA-1 Service Charge $/hp							
Time Related Load Charges									
Peak	$/ kW			9.00		9.00		9.00	
Mid Peak	$/ kW								
Off Peak	$/ kW								
		Off Peak Credit $/hp						minimum charge $/kW	
		(1.05)	(1.05)					25.55	11.05
Customer Charge									
	$/month	17.65	17.65	42.80	42.80	42.80	42.80	40.70	40.70
Meter Charge									
	$/month								

Table 2.3.2 PGE selected agricultural electric power rates, June 2001

Advice Letter 2119 - E May 22, 2001 Effective Date 06/01/01		AG-1A		AG-VB		AG-4B		AG-5B	
		Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Total Energy Charge									
Peak	$/kwh			0.28784		0.24489		0.17247	
Partial	$/kwh				0.11613		0.10960		0.07614
Off-peak	$/kwh			0.11586	0.10021	0.10277	0.09488	0.07041	0.06659
Flat	$/kwh	0.17860	0.17860			-	-	-	-
Generation									
Peak	$/kwh			0.21400		0.18331		0.12931	
Partial	$/kwh				0.06060		0.05816		0.03721
Off-peak	$/kwh			0.05612	0.04598	0.04740	0.04409	0.02725	0.02766
Flat	$/kwh	0.07775	0.08198						
Transmission - Distribution & Various									
Peak	$/kwh			0.03535		0.02380		0.01363	
Partial	$/kwh				0.01704		0.01386		0.00940
Off-peak	$/kwh			0.02125	0.01574	0.01759	0.01301	0.01363	0.00940
Flat	$/kwh	0.05773	0.05350			-	-	-	-
Energy Procurement Surcharge									
Peak	$/kwh			0.03849		0.03778		0.02953	
Partial	$/kwh				0.03849		0.03778		0.02953
Off-peak	$/kwh			0.03849	0.03849	0.03778	0.03778	0.02953	0.02953
Flat	$/kwh	0.04312	0.04312						
Connected Load -Demand Charges									
Monthly	$/ kW	2.40	2.20	2.90	1.75	2.90	1.75	6.55	4.40
Time Related Load Charges									
Peak	$/ kW			2.75		2.75		2.70	
Mid Peak	$/ kW								
Off Peak	$/ kW								
Customer Charge									
	$/month	12.00	12.00	16.00	16.00	16.00	16.00	16.00	16.00
Meter Charge									
	$/month			6.00	6.00	6.00	6.00	6.00	6.00

2.4.1 Agricultural Pumping Cost Model

This section reports on a spreadsheet model developed to estimate electricity costs under recent and new electricity rates for representative irrigation pumping situations. For major crops, the model incorporates important determinants of costs on a monthly basis. Seasonal crop water use, depth to water, and operating parameters of pump, well and field delivery systems were considered in the pumping cost estimates.

After explaining limitations of the model in Section 2.4.2, the components and parameters of the model are presented in Section 2.4.3. Finally, Section 2.4.4 presents summaries of the results.

2.4.2 Limitations

Because detailed information on the various aspects of individual pumping situations is not available, the model is intended to analyze representative, rather than actual cases. Further, conjunctive use of surface and deep well-pumped water is not considered. The model assumes all water is pumped and cost estimates are upper limits to the extent that availability of surface water reduces the amount of water pumped. This approach was taken because the availability of surface water, especially by month, varies significantly across regions and between individual pumping situations, and the requisite data to make even reasoned estimates is not available. The model does not provide information on differences between regions of the state. The representative situations considered in the model cover a range of typical situations so that readers from a particular area of the state will likely recognize a case similar to their own.

2.4.3 Model Components and Parameters

Figure 2.4.1 shows the basic components of the model's cost estimation approach. Broadly, there are three types of information required. First, crop water use and irrigation systems are identified. Then, pumping systems appropriate for the crop, irrigation delivery system, and depth-to-water are specified with particular flowrates and connected loads. This results in 45 different cases.

In the second step, monthly crop water use and the delivery – pumping system parameters are used to calculate kWh per month, hours of operation per month, and connected load. The third component applies rate schedules based on the connected load and calculates costs on a monthly basis. Four sets of estimates are obtained for each case: 2000, and June, 2001 for PG&E and SCE.

Figure 2.4.1 Model overview

SB282 Model V10d.xls

Crop Water Use and Irrigation Systems --- Monthly

Et based Crop Water Use, Monthly		Irrigation Systems	Crop - Irrigation Combinations (nine)	
alfalfa	SJV		alfalfa	flood
cotton	SJV	flood border/check	cotton	flood
grapes	SJ & Sac V	permanent set sprinklers	grapes	flood & lps
citrus	SJV	low pressure systems	citrus	pss & lps
almonds	SJ & Sac V		almonds	pss & lps
fruit	SJ & Sac V		fruit	flood

irrigation systems & deep wells
conjunctive use not considered

Five depth to water 10, 75, 150, 300, 600

45 cases analyzed: system gpm, TDH, kW & monthly crop use, del system efficiency =>
=> kwh, connected load, operating hours by month

Rates and Time Periods

Tariff Components

energy per kwh

connection charges
per kW per month
time related per kW
flat montly charges

Two Time Periods

Transition 2000 tariffs approved ~April 2000

Interim 2001 tariffs effective June 2001

Three Groups of Rates

			Transition	Interim
Group 1	<35 kW	PGE	AG-1A	AG-1A
		SCE	PA-1	PA-1
Group 2	35-100 kW	PGE	AG-4B	AG-4B
		SCE	PA-B	PA-B
Group 3	> 100 kW	PGE	AG-5B	AG-5B
		SCE	PA-5	PA-5

each case matched to rate group based on connected kW

four cost analyses per case, by time period and utility

Below, each of the components is discussed in turn, and an example for cotton is carried throughout to illustrate the model features.

2.4.3.1 Crop - Irrigation System Combinations

The nine crop-irrigation system combinations listed in Table 2.4.1. The annual and summer (June-August) crop water use are also shown. The table also gives the base parameter assumptions for each case, as discussed below.

Table 2.4.1

Crop-Irrigation System		Crop Water Use (1)		Delivery System		Field	Pump & Well
Crop	Delivery System	Annual ac-in	Jun-August ac-in	efficiency	Pressure psi	Size / Set acres	Capacity gpm
Cotton	Flood	34	26	70		160/20	1600
Alfalfa	Flood	57	24	70		160/20	1600
Fruit	Flood	41	21	70		40/20	1300
Grapes	Flood	32	19	70		40/20	1200
Grapes	LPS	32	19	85	20 (2)	40/40	800
Almonds	PSS	42	22	75	50 (2)	40/20	600
Almonds	LPS	42	22	85	20 (2)	40/40	900
Citrus	PSS	38	15	75	50 (2)	40/40	800
Citrus	LPS	38	15	85	20 (2)	40/40	1000

(1) Et based crop water use, Gross Water Required = Crop Water Use / Delivery System Efficiency
(2) Additional 250 gpm capacity allowed for filter operation

2.4.3.2 Crops and Water Use

The model considers six major irrigated crops grown in the Sacramento and/or San Joaquin Valleys of California: Cotton, Alfalfa, Grapes, Fruit, Almonds and Citrus. Monthly crop water use estimates for each crop were calculated from base reference evapo-transpiration rates (Et's) and crop specific coefficients reported in Hanson, Schwankl, and Fulton. The gross water which must be provided to meet the crop water needs, after allowing for losses due to delivery system efficiency is found by dividing the crop water use by the delivery system efficiency.

An important advantage of the monthly model is the ability to highlight seasonal pumping costs in summer, June- July- August. For example, Table 2.4.2 illustrates that for cotton, 77% of the annual crop water use occurs during summer. Importantly, of course, energy use and pumping costs follow the crop water use pattern.

Table 2.4.2 Monthly Crop Water Use and Pumping --- Cotton Example

Cotton Flood 180 acres 20 acres/set 70% del efficiency 1600 gpm

5

			Annual	January	February	March	April	May	June	July	August	September	October	November	December	Jun - Aug
Crop Water Required	ac-in/ac		34.4				0.9	3.5	8.6	10.2	7.6	3.6				26.4
Gross Water Require	ac-in/ac		49.15				1.29	5	12.29	14.57	10.86	5.14				37.72
Total Water Pumped	ac-ft		656				17	67	164	194	145	69				503
total operating hours			2208				58	225	552	654	488	231				1694
Percentage of water & op hrs			100%				3%	10%	25%	30%	22%	11%				77%
PGE hrs	winter	summer														
on peak		132	66.0							66.0						66
mid peak	286															
off peak	434	588	2142.0				58.0	225.0	552.0	588.0	488.0	231.0				1628
PGE	percent of hours															
on peak			3%							10%						4%
mid peak																
off peak			97%				100%	100%	100%	90%	100%	100%				96%
SCE hrs	winter	summer														
on peak		132	66.0							66.0						66
mid peak	286	198	458.0						162.0	198.0	98.0					458
off peak	434	390	1684.0				58.0	225.0	390.0	390.0	390.0	231.0				1170
SCE	percent of hours															
on peak			3%							10%						4%
mid peak			21%						29%	30%	20%					27%
off peak			76%				100%	100%	71%	60%	80%	100%				69%

2.4.3.3 Irrigation Systems

There are two components of an irrigation system: the delivery system and the pump-well. Three types of delivery systems are considered in the model. Pumping costs for ***Flood*** systems, e.g. border/check and furrow systems, require power to lift water from underground, or perhaps lift from a canal or reservoir. In addition, permanent set or movable sprinkler systems (***PSS***), and low pressure micro-sprinkler and drip systems (***LPS***) require additional power to pressurize the delivery systems. The delivery system operating parameters assumed for the model analyses shown in Table 2.4.2 above are consistent with reports by Solomon, and Hanson, Schwankl and Fulton.

For each of the nine crop-irrigation system combinations, the required flowrate (gpm) was determined from summer crop water use and assumed irrigation schedules. Delivery system parameters determine the rate and pressure at which the pump must deliver water. The size of the pump and motor required to yield the desired flow rate and operating pressure depends upon the depth to water level, and the pump and motor efficiencies. For each crop-irrigation combination, pumping systems were specified for five depth-to-water levels. Table 2.4.3 illustrates the development for flood-irrigated cotton and alfalfa which are assumed to have same systems. Appendix III: Irrigation Systems shows in detail how the parameters for flood and other systems were developed.

Table 2.4.3 Irrigation System Parameters, Cotton Example

Irrigation System Design & Operation		Flood Systems — Cotton & Alfalfa				
	Case	Flood-10	Flood-75	Flood-150	Flood-300	Flood-600
Design Parameters (—> indicates required assumption)						
—> Design Et (net crop use capacity)	ac-in/acre/month	8.0	8.0	8.0	8.0	8.0
—> delivery system oper efficiency		70%	70%	70%	70%	70%
—> delivery system oper pressure	psi	0	0	0	0	0
—> flowrate for filter backpressure	gpm	0	0	0	0	0
—> pumping depth to water	feet	10	75	150	300	600
—> field size	acres	160	160	160	160	160
—> acres irrigated per set	acres	20	20	20	20	20
—> hrs / set	hours	22	22	22	22	22
—> min irrigation interval	days	10	10	10	10	10
days / month		30	30	30	30	30
sets per month		24	24	24	24	24
max available pumping hours	hours/month	528	528	528	528	528
crop use / highest month	ac-in/acre	8.0	8.0	8.0	8.0	8.0
delivery system efficiency		70%	70%	70%	70%	70%
gross water-highest month	ac-in/acre	11.4	11.4	11.4	11.4	11.4
pumping required, high month	ac-ft /month	152	152	152	152	152
req'd flowrate @ max use	gpm	1551	1551	1551	1551	1551
add'l flowrate for filter operation	gpm	0	0	0	0	0
Deep Well & Pump						
—> pump design flowrate	gpm	1600	1600	1600	1600	1600
—> pump efficiency		70%	70%	70%	70%	70%
—> motor efficiency		90%	90%	90%	90%	90%
—> "wire to water"		63%	63%	63%	63%	63%
depth to water	feet	10	75	150	300	600
operating pressure	feet	0	0	0	0	0
allowance head loss	feet	10	10	10	10	10
Total Dynamic Head (TDH)	feet	20	85	160	310	610
kilowatt hours per ac-ft pumped	kwh	33	138	260	504	991
"water horsepower"	hp	8.1	34.3	64.6	125.3	246.5
kW-in	kW	12.8	54.5	102.6	196.8	391.2
HP-in	hp	9.6	40.7	76.5	148.3	291.8
connected load (kW-in rounded)	kW	10	50	100	200	390
overload factor	%					
rated horsepower	rhp	10				

In total, the model evaluates costs for 45 cases. These are considered representative of possible configurations, but it is noted that the multiplicity of design factors allows many different configurations which provide essentially the same crop water requirements. (See Schwankl, Pritchard, Hanson and Wellman). In all cases considered here, for simplicity, the pump, electric motor and "wire to water" efficiencies are assumed to be 70 percent, 90 percent and 63 percent respectively. The complete set of model cases is included in Appendix V.

2.4.3.4 Scheduling and Hours of Operation

The pumping and delivery system parameters are essentially fixed when the system is installed. Subsequently, crop water requirements determine the number of operating hours and the scheduling. Systems are designed to meet the highest crop water requirements in summer months. When crop needs are less than the system capacity, the options are either extend the interval between irrigations, or shorten the set time. (See Hanson, Schwankl and Fulton). Either approach results in the same total hours of operation and energy requirements.

Certainly an important consideration is scheduling to avoid peak times if the crop needs and system features allow, but it is recognized this is often not the case. The model is designed to calculate the number of pumping hours required in each month, and allocate these to non-peak times first. This process is illustrated for the cotton example in Table 2.4.4. However, industry experts report that flexibility is generally limited and the situations differ significantly, and thus attempts to define “typical” cases would be problematic. Therefore, the assumption made for all cases is that hours of pumping in a particular month are allocated to peak, mid-peak and off peak rates in proportion to the respective available hours in the utilities schedule. Table 2.4.4 shows that PG&E and SCE tariff schedules define different summer and winter periods, and different time periods with a day as peak, and the calculations which yield the allocation factors. The approach taken is conservative and yields upper estimates of costs to any extent that adjustments to avoid peak times can be achieved in practice.

Table 2.4.4 Peak, Mid-Peak and Off-Peak Allocation Factors

Peak, Mid-Peak, and Off-Peak allocation percentages. Assumptions used in model

PG&E		January	February	March	April	May	June	July	August	September	October	November	December
	on peak	0%	0%	0%	0%	18%	18%	18%	18%	18%	18%	0%	0%
	mid peak	40%	40%	40%	40%	0%	0%	0%	0%	0%	0%	40%	40%
	off peak	60%	60%	60%	60%	82%	82%	82%	82%	82%	82%	60%	60%

SCE		January	February	March	April	May	June	July	August	September	October	November	December
	on peak	0%	0%	0%	0%	0%	18%	18%	18%	18%	0%	0%	0%
	mid peak	40%	40%	40%	40%	40%	28%	28%	28%	28%	40%	40%	40%
	off peak	60%	60%	60%	60%	60%	54%	54%	54%	54%	60%	60%	60%

Summer

				PGE	SCE
		PGE	peak	18%	
			offpeak	82%	
		SCE	peak		18%
			midpeak		28%
			offpeak		54%
		days	hr/day	PGE	SCE
days per month		30	24	720	720
weekdays	peak	22	6	132	132
SCE	midpeak		9		198
SCE	offpeak		9		198
PGE	offpeak		18	396	
weekends	offpeak	8	24	192	192

Winter

				PGE	SCE
		PGE	peak	0%	
			partial	40%	
			offpeak	60%	
		SCE	peak		0%
			midpeak		40%
			offpeak		60%
		days	hr/day	PGE	SCE
days per month		30	24	720	720
weekdays		22		0	0
SCE	midpeak		13		286
PGE	partial		13	286	
	offpeak		11	242	242
weekends	offpeak	8	24	192	192

Tariff Definitions

PG&E	Summer	May 1 thru Oct 31	
	Summer	Peak	M-F Noon - 6:00 P
		Off Peak	all others
	Winter	Partial	M-F 8:30A - 9:30 P
		Off Peak	all others

SCE	Summer	1st Sunday June -- first Sunday Oct	
	Summer	Peak	M-F Noon - 6:00 P
		Mid Peak	M-F 8:00A - Noon & 6:00P - 11:00P
		Off Peak	all others
	Winter	Mid Peak	M-F 8:00A - 9:00 P
		Off Peak	all others

2.4.3.5 Electricity Rate Schedules Applied

Electricity rate schedules are matched to the cases, according to the connected load. Table 2.4.5 gives the connected loads by depth to water and crop-irrigation system.

Table 2.4.5

Crop-Irrigation System		Connected Load				
Crop	Delivery System	Depth to Water (Lift) in feet 10	75	150	300	600
		--- Kilo Watts ---				
Cotton	Flood	10	50	100	200	390
Alfalfa	Flood	10	50	100	200	390
Fruit	Flood	10	40	80	160	320
Grapes	Flood	10	40	80	150	290
Grapes	LPS	20	40	70	110	210
Almonds	PSS	30	50	60	100	170
Almonds	LPS	20	50	70	130	240
Citrus	PSS	40	60	90	130	230
Citrus	LPS	30	50	80	140	260

Table 2.4.6 identifies which rates are applied for a given connected load. In general, the cases with 10 ft lift assumed to be operating under the flat rate tariffs for small installations. The cases with 75 and 150 feet lift would be matched with the time of use rate schedules in Group Two. The larger installations are assumed to be under the Group Three "large agricultural motor" rates.

Table 2.4.6

Rate Groups by Connected Load, SCE & PG&E rate schedules

			Transition	Interim
Group 1	<35 kW	PGE	AG-1A	AG-1A
		SCE	PA-1	PA-1
Group 2	35-100 kW	PGE	AG-4B	AG-4B
		SCE	PA-B	PA-B
Group 3	> 100 kW	PGE	AG-5B	AG-5B
		SCE	PA-5	PA-5

Tables 2.4.7 to 2.4.11 give rate summaries for the three groups by utility. These show the comparable rates for the transition period through 2000, and recently adopted rates for June, 2001.

Table 2.4.7

Rate Summary: Group One under 35 kW, PG&E AG-1 A

Group One under 35 kW flat rates — PG & E AG-1 A — Effective 2000

		January	February	March	April	May	June	July	August	September	October	November	December
Energy Charges	$ / kwh												
flat		0.13548	0.13548	0.13548	0.13548	0.13548	0.13548	0.13548	0.13548	0.13548	0.13548	0.13548	0.13548
Connected Load Charges													
total, facilities related	$ / hp	2.20	2.20	2.20	2.20	2.40	2.40	2.40	2.40	2.40	2.40	2.20	2.20
total, time related													
on peak													
mid peak													
off peak													
Off Peak Credit	n/a												
Flat Charge total	$ / month	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00

Group One under 35 kW flat rates — PG & E AG-1 A — Effective June, 2001

		January	February	March	April	May	June	July	August	September	October	November	December
Energy Charges	$ / kwh												
flat		0.17860	0.17860	0.17860	0.17860	0.17860	0.17860	0.17860	0.17860	0.17860	0.17860	0.17860	0.17860
Connected Load Charges													
total, facilities related	$ / hp	2.20	2.20	2.20	2.20	2.40	2.40	2.40	2.40	2.40	2.40	2.20	2.20
total, time related													
on peak													
mid peak													
off peak													
Off Peak Credit	n/a												
Flat Charge total	$ / month	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00

Table 2.4.8

Rate Summary: Group One under 35 kW, SCE PA-1

Group One under 35 kW flat rates SCE PA - 1 Effective 2000

		January	February	March	April	May	June	July	August	September	October	November	December
Energy Charges	$ / kwh												
		0.09172	0.09172	0.09172	0.09172	0.09172	0.09172	0.09172	0.09172	0.09172	0.09172	0.09172	0.09172
		0.09172	0.09172	0.09172	0.09172	0.09172	0.09172	0.09172	0.09172	0.09172	0.09172	0.09172	0.09172
flat		0.09172	0.09172	0.09172	0.09172	0.09172	0.09172	0.09172	0.09172	0.09172	0.09172	0.09172	0.09172
Connected Load Charges													
total, facilities related	$ / hp	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05
total, time related													
on peak													
mid peak													
off peak													
Off Peak Credit	$ / hp	(1.05)	(1.05)	(1.05)	(1.05)	(1.05)	(1.05)	(1.05)	(1.05)	(1.05)	(1.05)	(1.05)	(1.05)
Flat Charge total	$ / month	17.65	17.65	17.65	17.65	17.65	17.65	17.65	17.65	17.65	17.65	17.65	17.65

Group One under 35 kW flat rates SCE PA - 1 Effective June, 2001

		January	February	March	April	May	June	July	August	September	October	November	December
Energy Charges	$ / kwh												
flat		0.12247	0.12247	0.12247	0.12247	0.12247	0.12247	0.12247	0.12247	0.12247	0.12247	0.12247	0.12247
Connected Load Charges													
total, facilities related	$ / hp	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05
total, time related													
on peak													
mid peak													
off peak													
Off Peak Credit	$ / hp	(1.05)	(1.05)	(1.05)	(1.05)	(1.05)	(1.05)	(1.05)	(1.05)	(1.05)	(1.05)	(1.05)	(1.05)
Flat Charge total	$ / month	17.65	17.65	17.65	17.65	17.65	17.65	17.65	17.65	17.65	17.65	17.65	17.65

Table 2.4.8

Rate Summary: Group Two 35 - 100 kW, PG&E AG- 4 B

Group Two 35 - 100 kW PG&E AG 4 - B Effective 2000

		January	February	March	April	May	June	July	August	September	October	November	December
Energy Charges	$ / kwh												
on peak						0.2071	0.2071	0.2071	0.2071	0.2071	0.2071		
mid peak		0.07179	0.07179	0.07179	0.07179							0.07179	0.07179
off peak		0.05476	0.05476	0.05476	0.05476	0.06498	0.06498	0.06498	0.06498	0.06498	0.06498	0.05476	0.05476
Connected Load Charges													
total, facilities related	$ / kW	1.75	1.75	1.75	1.75	2.90	2.90	2.90	2.90	2.90	2.90	1.75	1.75
total, time related	$ / kW												
on peak						2.75	2.75	2.75	2.75	2.75	2.75		
mid peak													
off peak													
Minimum Demand	n/a												
Flat Charg total	$ / month	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00

Group Two 35 - 100 kW PG&E AG 4 - B Effective June, 2001

		January	February	March	April	May	June	July	August	September	October	November	December
Energy Charges	$ / kwh												
on peak						0.24489	0.24489	0.24489	0.24489	0.24489	0.24489		
mid peak		0.10960	0.10960	0.10960	0.10960							0.10960	0.10960
off peak		0.09488	0.09488	0.09488	0.09488	0.10277	0.10277	0.10277	0.10277	0.10277	0.10277	0.09488	0.09488
Connected Load Charges													
total, facilities related	$ / kW	1.75	1.75	1.75	1.75	2.90	2.90	2.90	2.90	2.90	2.90	1.75	1.75
total, time related	$ / kW												
on peak						2.75	2.75	2.75	2.75	2.75	2.75		
mid peak													
off peak													
Minimum Demand	n/a												
Flat Charg total	$ / month	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00

Table 2.4.9

Rate Summary: Group Two 35 - 100 kW, SCE TOU PA -B

Group Two 35 - 100 kW — SCE TOU PA -B — Effective 2000

		January	February	March	April	May	June	July	August	September	October	November	December
Energy Charges	$ / kwh												
on peak							0.11229	0.08008	0.08008	0.08008			
mid peak		0.06083	0.06083	0.06083	0.06083	0.08503	0.07256	0.05203	0.05203	0.05203	0.06083	0.06083	0.06083
off peak		0.04981	0.04981	0.04981	0.04981	0.03952	0.03952	0.04344	0.04344	0.04344	0.04981	0.04981	0.04981
Connected Load Charges													
total, facilities related	$ / kW	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85
total, time related	$ / kW												
on peak							9.00	9.00	9.00	9.00			
mid peak													
off peak													
Minimum Charge	n/a												
Flat Charge total	$ / month	42.80	42.80	42.80	42.80	42.80	42.80	42.80	42.80	42.80	42.80	42.80	42.80

Group Two 35 - 100 kW — SCE TOU PA -B — Effective June, 2001

		January	February	March	April	May	June	July	August	September	October	November	December
Energy Charges	$ / kwh												
on peak							0.17408	0.17408	0.17408	0.17408			
mid peak		0.11003	0.11003	0.11003	0.11003	0.11003	0.09756	0.09756	0.09756	0.09756	0.11003	0.11003	0.11003
off peak		0.06452	0.06452	0.06452	0.06452	0.06452	0.06452	0.06452	0.06452	0.06452	0.06452	0.06452	0.06452
Connected Load Charges													
total, facilities related	$ / kW	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85
total, time related	$ / kW												
on peak							9.00	9.00	9.00	9.00			
mid peak													
off peak													
Minimum Charge	n/a												
Flat Charge total	$ / month	42.80	42.80	42.80	42.80	42.80	42.80	42.80	42.80	42.80	42.80	42.80	42.80

Table 2.4.10

Rate Summary: Group Three over 100 kW, PG&E AG - 5 B

Group Three over 100 kW — PG&E AG 5 - B — Effective 2000

		January	February	March	April	May	June	July	August	September	October	November	December
Energy Charges	$ / kwh												
on peak						0.14294	0.14294	0.14294	0.14294	0.14294	0.14294		
mid peak		0.04661	0.04661	0.04661	0.04661							0.04661	0.04661
off peak		0.03706	0.03706	0.03706	0.03706	0.04088	0.04088	0.04088	0.04088	0.04088	0.04088	0.03706	0.03706
Connected Load Charges													
total, facilities related	$ / kW	4.40	4.40	4.40	4.40	6.55	6.55	6.55	6.55	6.55	6.55	4.40	4.40
total, time related	$ / kW												
on peak						2.70	2.70	2.70	2.70	2.70	2.70		
mid peak													
off peak													
Minimum Demand	n/a												
Flat Charg total	$ / month	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00

Group Three over 100 kW — PG&E AG 5 - B — Effective June, 2001 — PG&E June 2001

		January	February	March	April	May	June	July	August	September	October	November	December
Energy Charges	$ / kwh												
on peak						0.17247	0.17247	0.17247	0.17247	0.17247	0.17247		
mid peak		0.07614	0.07614	0.07614	0.07614							0.07614	0.07614
off peak		0.06659	0.06659	0.06659	0.06659	0.07041	0.07041	0.07041	0.07041	0.07041	0.07041	0.06659	0.06659
Connected Load Charges													
total, facilities related	$ / kW	4.40	4.40	4.40	4.40	6.55	6.55	6.55	6.55	6.55	6.55	4.40	4.40
total, time related	$ / kW												
on peak						2.70	2.70	2.70	2.70	2.70	2.70		
mid peak													
off peak													
Minimum Demand	n/a												
Flat Charg total	$ / month	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00

Table 2.4.11

Rate Summary: Group Three over 100 kW, SCE TOU PA - 5

Group Three over 100 kW — SCE — TOU PA - 5 — Effective 2000

		January	February	March	April	May	June	July	August	September	October	November	December
Energy Charges	$ / kwh												
on peak							0.07947	0.07947	0.07947	0.07947			
mid peak		0.06022	0.06022	0.06022	0.06022	0.06022	0.05142	0.05142	0.05142	0.05142	0.06022	0.06022	0.06022
off peak		0.04920	0.04920	0.04920	0.04920	0.04920	0.04283	0.04283	0.04283	0.04283	0.04920	0.04920	0.04920
Connected Load Charges													
total, facilities related	$ / kW	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85
total, time related	$ / kW												
on peak							9.00	9.00	9.00	9.00			
mid peak													
off peak													
Minimum Charge	$/ kW	11.05	11.05	11.05	11.05	11.05	25.55	25.55	25.55	25.55	11.05	11.05	11.05
Flat Charge total	$ / month	40.70	40.70	40.70	40.70	40.70	40.70	40.70	40.70	40.70	40.70	40.70	40.70

Group Three over 100 kW — SCE — TOU PA - 5 — Effective June, 2001

		January	February	March	April	May	June	July	August	September	October	November	December
Energy Charges	$ / kwh												
on peak							0.13545	0.13545	0.13545	0.13545			
mid peak		0.08422	0.08422	0.08422	0.08422	0.08422	0.07542	0.07542	0.07542	0.07542	0.08422	0.08422	0.08422
off peak		0.07320	0.07320	0.07320	0.07320	0.07320	0.06683	0.06683	0.06683	0.06683	0.07320	0.07320	0.07320
Connected Load Charges													
total, facilities related	$ / kW	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85
total, time related	$ / kW												
on peak							9.00	9.00	9.00	9.00			
mid peak													
off peak													
Minimum Charge	$/ kW	11.05	11.05	11.05	11.05	11.05	25.55	25.55	25.55	25.55	11.05	11.05	11.05
Flat Charge total	$ / month	40.70	40.70	40.70	40.70	40.70	40.70	40.70	40.70	40.70	40.70	40.70	40.70

2.4.3.6 Case Summaries

The model sequentially takes each of the 45 cases and uses the SCE and PG&E rates for the respective rate group, and calculates costs broken down into three categories by month: energy charges, connected load charges, and fixed monthly charges. These results for the 45 cases are transferred to a database from which the summary measures are obtained. To illustrate, Table 2.4.12 is an example of the Case Summary for flood irrigated cotton with pumping from 150 feet. The connected load is 100 kW so the Group Two rates are used.

Table 2.4.12 Case Summary Group Two Rates, Cotton Example

Case Summary with Cost Comparisons: **Group Two Rates** **Cotton** **Flood** **150 ft lift**

		Annual	January	February	March	April	May	June	July	August	September	October	November	December	Jan - Aug
Crop Water Required	ac-in/ac	34.4	-	-	-	0.9	3.5	8.6	10.2	7.6	3.6	-	-	-	26.4
Gross Water Required	ac-in/ac	49.2	-	-	-	1.3	5.0	12.3	14.6	10.9	5.1	-	-	-	37.7
Total Water Pumped	ac-ft	656.0				17	67	164	194	145	69				503.0
kilowatt hours	kwh	170,800	-	-	-	4,421	17,424	42,650	50,452	37,709	17,944	-	-	-	130,811
total operating hours		2208				58	225	552	654	488	231				1694
Percentage of water, kwh & op hrs		100%				3%	10%	25%	30%	22%	11%				77%
PG&E	**2000**	**AG 4 - B**													
Energy		12,366				272	1,329	3,086	3,851	2,729	1,299				9,466
Connection Chgs		4,440	175	175	175	175	565	565	565	565	565	565	175	175	1,695
Flat Charges		264	22	22	22	22	22	22	22	22	22	22	22	22	66
Total Charges		17,070	197	197	197	469	1,916	3,673	4,238	3,316	1,886	587	197	197	11,227
PG&E	**June, 2001**	**AG 4 - B**													
Energy		17,100				446	1,842	4,247	5,024	3,756	1,787				13,026
Connection Chgs		4,440	175	175	175	175	565	565	565	565	565	565	175	175	1,695
Flat Charges		264	22	22	22	22	22	22	22	22	22	22	22	22	66
Total Charges		21,804	197	197	197	643	2,429	4,834	5,611	4,342	2,374	587	197	197	14,787
SCE	**2000**	**PA - B**													
Energy		9,448				240	1,006	2,639	2,646	1,877	941				7,262
Connection Chgs		7,020	285	285	285	285	285	1,185	1,185	1,185	1,185	285	285	285	3,555
Flat Charges		514	43	43	43	43	43	43	43	43	43	43	43	43	128
Total Charges		16,982	328	328	328	568	1,334	3,867	3,874	3,205	2,169	328	328	328	10,945
SCE	**June, 2001**	**PA - B**													
Energy		15,715				366	1,441	3,987	4,717	3,525	1,678				12,230
Connection Chgs		7,020	285	285	285	285	285	1,185	1,185	1,185	1,185	285	285	285	3,555
Flat Charges		514	43	43	43	43	43	43	43	43	43	43	43	43	128
Total Charges		23,248	328	328	328	694	1,769	5,215	5,945	4,753	2,905	328	328	328	15,913

Case parameters: 160 acres 20 acres/set 70% delivery sys efficiency 1600 gpm 100.0 connected kW

The model could be extended to analyze potential choices between rate structures. Table 2.4.13 shows the Case Summary for the same cotton pumping situation but using Group Three rates. It is interesting to note the costs are similar under either rate structure, but there is a tradeoff between energy costs and connected load charges. Under Group Three, the seasonal nature of agricultural pumping is particularly important. For example note SCE's minimum charge in Group Three is applicable in eight months. The higher Group Three connected load charges would be relatively less important for pumping situations with more hours of use and for which use is less seasonal. Although beyond the scope of this report, this is issue will become more important in the future if special agricultural rates for large pumping are changed or switched to general industry rate structures.

Table 2.4.13 Case Summary, Group Three Rates, Cotton Example.

Case Summary with Cost Comparisons: **Group Three Rates** **Cotton** **Flood** **150 ft lift**

		Annual	January	February	March	April	May	June	July	August	September	October	November	December	Jun - Aug
Crop Water Required	ac-in/ac	34.4	-	-	-	0.9	3.5	8.6	10.2	7.6	3.6	-	-	-	26.4
Gross Water Required	ac-in/ac	49.2	-	-	-	1.3	5.0	12.3	14.6	10.9	5.1	-	-	-	37.7
Total Water Pumped	ac-ft	656.0				17	67	164	194	145	69				503.0
kilowatt hours	kwh	170,600	-	-	-	4,421	17,424	42,650	50,452	37,709	17,944	-	-	-	130,811
total operating hours		2208				58	225	552	654	488	231				1694
Percentage of water, kwh & op hrs		100%				3%	10%	25%	30%	22%	11%				77%
PG&E	**2000**	**AG - 5 B**													
Energy		10,027				181	1,032	2,527	2,989	2,234	1,063				7,751
Connection Chgs		8,190	440	440	440	440	925	925	925	925	925	925	440	440	2,775
Flat Charges		264	22	22	22	22	22	22	22	22	22	22	22	22	66
Total Charges		18,481	462	462	462	643	1,979	3,474	3,936	3,181	2,010	947	462	462	10,592
PG&E	**June, 2001**	**AG - 5 B**													
Energy		15,065				311	1,547	3,787	4,479	3,348	1,593				11,614
Connection Chgs		8,190	440	440	440	440	925	925	925	925	925	925	440	440	2,775
Flat Charges		264	22	22	22	22	22	22	22	22	22	22	22	22	66
minimum charge															
Total Charges		23,519	462	462	462	773	2,494	4,734	5,426	4,295	2,540	947	462	462	14,455
SCE	**2000**	**PA - 5**													
Energy		8,881				237	934	2,211	2,615	1,954	930				6,780
Connection Chgs		7,020	285	285	285	285	285	1,185	1,185	1,185	1,185	285	285	285	3,555
Flat Charges		488	41	41	41	41	41	41	41	41	41	41	41	41	122
			1,105	1,105	1,105	1,105	1,105	2,555	2,555	2,555	2,555	1,105	1,105	1,105	
Total Charges		16,390	1,105	1,105	1,105	1,105	1,260	3,436	3,841	3,180	2,555	1,105	1,105	1,105	10,457
SCE	**June, 2001**	**PA - 5**													
Energy		13,832				343	1,352	3,480	4,118	3,077	1,464				10,672
Connection Chgs		7,020	285	285	285	285	285	1,185	1,185	1,185	1,185	285	285	285	3,555
Flat Charges		488	41	41	41	41	41	41	41	41	41	41	41	41	122
minimum charge			1,105	1,105	1,105	1,105	1,105	2,555	2,555	2,555	2,555	1,105	1,105	1,105	
Total Charges		21,340	1,105	1,105	1,105	1,105	1,678	4,705	5,342	4,302	2,690	1,105	1,105	1,105	14,350

Case parameters: 160 acres; 20 acres/set; 70% delivery sys efficiency; 1600 gpm; 100.0 connected kW

2.4.4 Model Results

The following nine tables, Tables 2.4.14 to 2.4.23, summarize the model estimates of costs. There is one table for each crop-irrigation system and the results can be used to compare costs between the two periods and between utility rate schedules comparisons of costs by commodity. For example, for Group Two, time of use schedules for medium size pumping systems, Table 2.4.14 indicates costs will increase over last year,

Table 2.4.14

Group Two Cost Comparison, Transition 2000, and Interim June 2001

crop	irrigation system	depth to water - lift	PG&E	SCE
			percent change	
Cotton	Flood	75-150 ft	26-27 %	35-37 %
Alfalfa	Flood	75-150 ft	35-36 %	40-41 %
Fruit	Flood	75-150 ft	19-20 %	18-19 %
Grapes	Flood	75-150 ft	17-17 %	16-16 %
Grapes	LPS	75-150 ft	19-19 %	19-19 %
Almonds	PSS	75-150 ft	26-28 %	28-31 %
Almonds	LPS	75-150 ft	21-22 %	20-23 %
Citrus	PSS	75-150 ft	25-25 %	23-22 %
Citrus	LPS	75-150 ft	21-21 %	17-19 %

Table 2.4.15

Summary Cost Comparion	ALFALFA		FLOOD			160 acres		1,091 ac-ft / yr	
	Connected Load		Transition			Interim			
Depth to Water	Rates (a)		$/kwh	$/ac-ft	$/acre	$/kwh	$/ac-ft	$/acre	
Alfalfa - 10	10 kW								chg : transition
	G1	PGE	0.116	4	26	0.156	5	35	35%
	G1	SCE	0.085	3	19	0.136	4	30	58%
Alfalfa - 75	50 kW								
	G2	PGE	0.087	12	82	0.118	16	111	35%
	G2	SCE	0.082	11	77	0.115	16	108	40%
Alfalfa - 150	100 kW								
	G3	PGE	0.087	23	154	0.118	31	209	36%
	G3	SCE	0.082	21	145	0.115	30	204	41%
Alfalfa - 300	200 kW								
	G3	PGE	0.084	43	290	0.114	57	391	35%
	G3	SCE	0.079	40	272	0.106	54	365	34%
Alfalfa - 600	390 kW								
	G3	PGE	0.084	83	567	0.113	112	767	35%
	G3	SCE	0.078	78	530	0.105	105	713	35%

(a) Rate Group 1 connected load < 35 kW PG&E AG-1A, AG-1A SCE PA-1, PA-1
Rate Group 2 connected load 35 - 100 kW PG&E AG-4B, AG-4B SCE PA-B, PA-B
Rate Group 3 connected load > 100 kW PG&E AG-5B, AG-5B SCE PA-5, PA-5

Table 2.4.16

Summary Cost Comparion ALMONDS LOW PRESSURE SPRINKLER: 40 acres 167 ac-ft / yr

Depth to Water	Connected Load Rates (a)		Transition $/kwh	Transition $/ac-ft	Transition $/acre	Interim $/kwh	Interim $/ac-ft	Interim $/acre	chg : transition
Almonds - 10	20 kW								
	G1	PGE	0.122	13	53	0.173	18	75	42%
	G1	SCE	0.099	10	43	0.123	13	53	23%
Almonds - 75	50 kW								
	G2	PGE	0.143	30	125	0.172	36	151	21%
	G2	SCE	0.170	36	149	0.205	43	179	20%
Almonds - 150	70 kW								
	G2	PGE	0.133	44	184	0.162	54	224	22%
	G2	SCE	0.153	51	212	0.188	62	260	23%
Almonds - 300	130 kW								
	G3	PGE	0.170	98	409	0.200	115	480	17%
	G3	SCE	0.153	88	366	0.180	104	433	18%
Almonds - 600	240 kW								
	G3	PGE	0.169	180	750	0.199	211	881	17%
	G3	SCE	0.150	160	666	0.178	189	789	18%

(a) Rate Group 1 connected load < 35 kW PG&E AG-1A, AG-1A SCE PA-1, PA-1
Rate Group 2 connected load 35 - 100 kW PG&E AG-4B, AG-4B SCE PA-B, PA-B
Rate Group 3 connected load > 100 kW PG&E AG-5B, AG-5B SCE PA-5, PA-5

Table 2.4.17

Summary Cost Comparion ALMONDS PERMANENT SET SPRINKLEF 40 acres 188 ac-ft / yr

	Connected Load		Transition			Interim			
Depth to Water	Rates (a)		$/kwh	$/ac-ft	$/acre	$/kwh	$/ac-ft	$/acre	chg : transition
Almonds - 10	30 kW								
	G1	PGE	0.114	24	113	0.157	33	156	38%
	G1	SCE	0.085	18	85	0.109	23	108	27%
Almonds - 75	50 kW								
	G2	PGE	0.114	36	169	0.143	45	213	26%
	G2	SCE	0.123	39	183	0.157	50	234	28%
Almonds - 150	60 kW								
	G2	PGE	0.107	47	221	0.137	60	282	28%
	G2	SCE	0.112	49	232	0.147	65	303	31%
Almonds - 300	100 kW								
	G3	PGE	0.109	74	348	0.138	94	442	27%
	G3	SCE	0.114	78	365	0.149	101	477	31%
Almonds - 600	170 kW								
	G3	PGE	0.121	142	668	0.151	177	831	24%
	G3	SCE	0.109	127	599	0.137	160	752	26%

(a) Rate Group 1	connected load < 35 kW	PG&E AG-1A, AG-1A	SCE PA-1, PA-1
Rate Group 2	connected load 35 - 100 kW	PG&E AG-4B, AG-4B	SCE PA-B, PA-B
Rate Group 3	connected load > 100 kW	PG&E AG-5B, AG-5B	SCE PA-5, PA-5

Table 2.4.18

Summary Cost Comparion CITRUS LOW PRESSURE SPRINKLER: 40 acres 149 ac-ft / yr

Depth to Water	Connected Load Rates (a)		Transition $/kwh	Transition $/ac-ft	Transition $/acre	Interim $/kwh	Interim $/ac-ft	Interim $/acre	chg : transition
Citrus - 10	30 kW								
	G1	PGE	0.133	14	51	0.189	20	73	43%
	G1	SCE	0.109	11	42	0.167	17	65	55%
Citrus - 75	50 kW								
	G2	PGE	0.149	31	117	0.181	38	141	21%
	G2	SCE	0.184	39	144	0.217	46	169	17%
Citrus - 150	80 kW								
	G2	PGE	0.147	49	182	0.178	59	220	21%
	G2	SCE	0.179	59	221	0.212	70	262	19%
Citrus - 300	140 kW								
	G3	PGE	0.190	110	408	0.220	127	471	15%
	G3	SCE	0.173	100	371	0.200	115	428	15%
Citrus - 600	260 kW								
	G3	PGE	0.190	202	751	0.219	233	868	16%
	G3	SCE	0.171	182	677	0.198	210	784	16%

(a) Rate Group 1 connected load < 35 kW PG&E AG-1A, AG-1A SCE PA-1, PA-1
Rate Group 2 connected load 35 - 100 kW PG&E AG-4B, AG-4B SCE PA-B, PA-B
Rate Group 3 connected load > 100 kW PG&E AG-5B, AG-5B SCE PA-5, PA-5

Table 2.4.19

Summary Cost Comparion CITRUS PERMANENT SET SPRINKLEF 40 acres 167 ac-ft / yr

Depth to Water	Connected Load Rates (a)		Transition $/kwh	Transition $/ac-ft	Transition $/acre	Interim $/kwh	Interim $/ac-ft	Interim $/acre	chg : transition
Citrus - 10	40 kW								
	G2	PGE	0.128	27	113	0.159	34	140	24%
	G2	SCE	0.149	32	132	0.182	39	161	22%
Citrus - 75	60 kW								
	G2	PGE	0.125	40	166	0.156	50	207	25%
	G2	SCE	0.144	46	191	0.177	56	235	23%
Citrus - 150	90 kW								
	G2	PGE	0.128	56	234	0.159	70	292	25%
	G2	SCE	0.148	65	272	0.181	80	332	22%
Citrus - 300	130 kW								
	G3	PGE	0.149	102	426	0.179	122	510	20%
	G3	SCE	0.137	94	391	0.164	112	467	19%
Citrus - 600	230 kW								
	G3	PGE	0.151	177	740	0.181	212	884	19%
	G3	SCE	0.138	161	673	0.165	193	805	20%

(a) Rate Group 1 connected load < 35 kW PG&E AG-1A, AG-1A SCE PA-1, PA-1
Rate Group 2 connected load 35 - 100 kW PG&E AG-4B, AG-4B SCE PA-B, PA-B
Rate Group 3 connected load > 100 kW PG&E AG-5B, AG-5B SCE PA-5, PA-5

Table 2.4.20

Summary Cost Comparion COTTON FLOOD 160 acres 656 ac-ft / yr

Depth to Water	Connected Load Rates (a)			Transition $/kwh	Transition $/ac-ft	Transition $/acre	Interim $/kwh	Interim $/ac-ft	Interim $/acre	chg : transition
Cotton - 10	10 kW									
		G1	PGE	0.109	4	15	0.150	5	20	33%
		G1	SCE	0.084	3	11	0.107	4	14	27%
Cotton - 75	50 kW									
		G2	PGE	0.100	14	57	0.128	18	72	26%
		G2	SCE	0.100	14	57	0.137	19	77	35%
Cotton - 150	100 kW									
		G3	PGE	0.100	26	107	0.128	33	136	27%
		G3	SCE	0.100	26	106	0.136	35	145	37%
Cotton - 300	200 kW									
		G3	PGE	0.109	55	225	0.139	70	286	27%
		G3	SCE	0.096	48	198	0.125	63	256	30%
Cotton - 600	390 kW									
		G3	PGE	0.108	107	440	0.138	137	560	27%
		G3	SCE	0.095	94	386	0.124	123	504	31%

(a) Rate Group 1 connected load < 35 kW PG&E AG-1A, AG-1A SCE PA-1, PA-1
Rate Group 2 connected load 35 - 100 kW PG&E AG-4B, AG-4B SCE PA-B, PA-B
Rate Group 3 connected load > 100 kW PG&E AG-5B, AG-5B SCE PA-5, PA-5

Table 2.4.21

Summary Cost Comparion FRUIT FLOOD 40 acres 192 ac-ft / yr

Depth to Water	Connected Load Rates (a)		Transition $/kwh	Transition $/ac-ft	Transition $/acre	Interim $/kwh	Interim $/ac-ft	Interim $/acre	chg : transition
Fruit - 10	10 kW								
	G1	PGE	0.134	4	21	0.196	6	31	48%
	G1	SCE	0.125	4	20	0.149	5	23	15%
Fruit - 75	40 kW								
	G2	PGE	0.149	21	99	0.178	25	118	19%
	G2	SCE	0.181	25	120	0.215	30	142	18%
Fruit - 150	80 kW								
	G2	PGE	0.148	39	185	0.178	46	222	20%
	G2	SCE	0.178	46	222	0.212	55	265	19%
Fruit - 300	160 kW								
	G3	PGE	0.195	98	471	0.224	113	543	15%
	G3	SCE	0.174	88	420	0.201	101	487	16%
Fruit - 600	320 kW								
	G3	PGE	0.196	194	931	0.225	223	1,072	15%
	G3	SCE	0.173	172	824	0.201	199	955	16%

(a) Rate Group 1	connected load < 35 kW	PG&E	AG-1A, AG-1A	SCE PA-1, PA-1
Rate Group 2	connected load 35 - 100 kW	PG&E	AG-4B, AG-4B	SCE PA-B, PA-B
Rate Group 3	connected load > 100 kW	PG&E	AG-5B, AG-5B	SCE PA-5, PA-5

Table 2.4.22

Summary Cost Comparion GRAPES FLOOD 40 acres 150 ac-ft / yr

Depth to Water	Connected Load Rates (a)		Transition $/kwh	Transition $/ac-ft	Transition $/acre	Interim $/kwh	Interim $/ac-ft	Interim $/acre	chg : transition
Grapes - 10	10 kW								
	G1	PGE	0.138	5	17	0.206	7	25	47%
	G1	SCE	0.137	4	17	0.160	5	20	18%
Grapes - 75	40 kW								
	G2	PGE	0.171	24	88	0.199	28	103	17%
	G2	SCE	0.216	30	112	0.251	35	130	16%
Grapes - 150	80 kW								
	G2	PGE	0.170	44	166	0.199	52	194	17%
	G2	SCE	0.213	55	207	0.248	64	241	16%
Grapes - 300	150 kW								
	G3	PGE	0.224	113	422	0.253	128	478	13%
	G3	SCE	0.198	100	374	0.226	114	428	14%
Grapes - 600	290 kW								
	G3	PGE	0.219	217	814	0.249	246	924	14%
	G3	SCE	0.192	191	716	0.221	219	820	15%

(a) Rate Group 1 connected load < 35 kW PG&E AG-1A, AG-1A SCE PA-1, PA-1
Rate Group 2 connected load 35 - 100 kW PG&E AG-4B, AG-4B SCE PA-B, PA-B
Rate Group 3 connected load > 100 kW PG&E AG-5B, AG-5B SCE PA-5, PA-5

Table 2.4.23

Summary Cost Comparion GRAPES LOW PRESSURE SPRINKLER: 40 acres 124 ac-ft / yr

Depth to Water	Connected Load Rates (a)		Transition $/kwh	Transition $/ac-ft	Transition $/acre	Interim $/kwh	Interim $/ac-ft	Interim $/acre	chg : transition
Grapes - 10	20 kW								
	G1	PGE	0.125	13	40	0.179	19	58	45%
	G1	SCE	0.105	11	34	0.128	13	41	21%
Grapes - 75	40 kW								
	G2	PGE	0.151	32	98	0.179	38	117	19%
	G2	SCE	0.183	38	119	0.218	46	142	19%
Grapes - 150	70 kW								
	G2	PGE	0.154	51	158	0.183	61	188	19%
	G2	SCE	0.187	62	193	0.222	74	229	19%
Grapes - 300	110 kW								
	G3	PGE	0.187	108	334	0.217	125	387	16%
	G3	SCE	0.167	96	299	0.196	113	349	17%
Grapes - 600	210 kW								
	G3	PGE	0.190	202	626	0.219	233	723	15%
	G3	SCE	0.168	179	553	0.196	208	646	17%

(a) Rate Group 1 connected load < 35 kW PG&E AG-1A, AG-1A SCE PA-1, PA-1
Rate Group 2 connected load 35 - 100 kW PG&E AG-4B, AG-4B SCE PA-B, PA-B
Rate Group 3 connected load > 100 kW PG&E AG-5B, AG-5B SCE PA-5, PA-5

2.5 Rate Change Effects on Dairies

In this section, the focus is on the effects of rate changes in California's dairy sector. The approach is based on utility invoices from a sample of dairies and comparisons of costs between 1999-2000 actual and estimates using June 2001 rate schedules. Section 2.5.1 provides an overview of electricity use by dairies. Section 2.5.2 presents the results of the bill comparisons. Section 2.5.3 extrapolates the results to the sector, and gives observations and conclusions.

2.5.1 Overview of Electric Power Use by Dairy Operations

Dairies in California are totally dependent on electric power for daily operation. And the cost of electric service for the typical dairy operation is a significant part of monthly operational budgets. All dairy operations will have multiple accounts, each with a separate meter installed. Each of the meters will be associated with a part (e.g., milking parlor, sump pump, well water) of the entire operation. In many cases, the total of monthly electrical invoices exceeds $3,000.

The primary uses of electrical power at dairies are refrigeration and compressors, milk and vacuum pumps, lighting and ventilation fans (Peebles and Reinemann, 1994; Collar et al, 1996a; Collar et al, 1996b). Less than 10 percent of dairies use electricity to heat water (most use natural gas or propane). Milk is typically pre-cooled using heat exchangers with well water and well water and chilled water. Total connected load (hp) and electricity use increase with herd size. Studies suggest that connected hp per cow averages about 0.08 hp. However, energy used for milk production (milk/kWh) is not related to herd size (suggesting that efficiency measures are in place, or at least that economies of scale with respect to milk/kWh, are not available to those who seek to expand herd size).

Electricity costs are a significant element in dairy costs. Monthly electricity invoices for a number of dairies in Humboldt County and Tulare County (discussed below), show that electric power use varies little from month to month, again leading to the conclusion that the derived demand for electricity is based primarily on well-defined hp requirements, lighting needs, and operation over a fairly consistent number of hours each day. Most dairies milk twice each day, and avoid daily "peak" electricity prices by so doing.

2.5.2 Analysis of Dairies' Electric Power Costs

As evidence of the importance of electricity costs in dairy, the Table 2.5.1 presents summary data from a representative San Joaquin Valley dairy operation. The dairy milks about 620 cows at any one time. The costs reflect average winter monthly costs and include customer and meter costs as well as energy costs.

Table 2.5.1

Example electricity costs for San Joaquin Valley dairy operation

Facility	Meters number	Average Invoice $/ month	Average Use kWh/month	Average cost $/ kWh	SCE Rate Schedule
Milking Barn	1	900	14,500	.062	TOU-PA-5
Barn Well	1	1,160	10,800	.107	PA-1
Sump Pump	1	530	5,100	.104	PA-1
Other barns	3	200	1,500	.133	GS-1
Combined		2,700			

Multiplying the monthly total cost by 12 months provides for a minimum (since summer month prices are not included) annual electricity cost of $33,500 for a dairy of this size. The cost per kWh column illustrates the range of prices that were paid for electricity, as well as the importance of seeking out the least expensive rate structure available.

Table 2.5.2 shows a comparison of monthly kWh usage between sampled dairies in Humboldt County, Tulare County, and two studies of a large number of dairies in the San Joaquin Valley. The data in the table for milking facility accounts numbered A through F were assembled from monthly electric utility invoices used for this study. Milking facility account numbers A through F report on only electricity use at the milking parlor meter and do not include ancillary operations. Studies #1 and #2 do include these operations. Average monthly kWh per cow does varies for accounts A through F, but this is probably due to the number of different motors and lighting systems that are actually behind the one meter used for each account in this table. Studies #1 and #2 report monthly kWh/cow slightly in excess of 40.

Table 2.5.2

Comparison of Average Monthly kWh Usage and Costs between Sampled Dairies and Studies of Electrical Usage at Dairies in the Southern San Joaquin Valley

Milking Facility Account	Average Monthly kWh	Average Number of Cows being Milked	Monthly kWh/cow	Average Monthly Total Invoice ($)	Average Monthly C & M(1) cost ($)	Average Monthly Energy cost ($)	Average Monthly PX cost ($)	PX price as % of total
A	8176	308	26.5	554	129	425	375	67.6%
B	5949	440	13.5	483	178	305	229	47.4%
C	2811	106	26.5	285	65	220	107	37.5%
D	21447	616	34.8	1481	349	1132	709	47.9%
E	22689	748	30.3	1416	184	1232	711	50.2%
F	14522	616	23.6	899				
Study #1		948	41.9					
Study #2	48758	1150	42.5					

(1) customer and meter

Facility accounts A through F are actual dairy operations. Monthly kWh usage reflects only the kWh associated with the one meter directly associated with the milking facility (and not any additional meters such as a separate calving barn) Dairies A-C are located in the north coast area and dairies D-F are located in the San Joaquin Valley.

Facility account numbers Study #1 and #2 are reported averages from studies of 93 dairies and 42 dairies, respectively, in the San Joaquin Valley. These studies incorporated electric power usage for more on-site operations than just the milking facility.

Monthly average invoice totals are shown as are monthly average meter and customer charges, monthly average energy costs, and monthly average PX costs for each facility account. Meter and customer charges combined range from a low of $65/month for a smaller scale operation up to about $350/month for a larger operation. Average monthly PX costs as a percentage of the average monthly total invoice ranged from a low of 47 percent to a high of 68 percent.

2.5.3 Projections and Conclusions

Table 2.5.3 summarizes information from Appendix V and shows the number of dairy cows by geographic area, as well as estimated existing and projected monthly and annual electricity costs for PG&E and SCE service areas in California.

Table 2.5.3

Number of Dairy Cows by Geographic Area, Estimated Monthly kWh Usage, and Estimated Monthly Electric Service Costs under Existing and Possible Future Rate Schedules, with Focus upon Dairies in PG&E and SCE Service Areas

PG&E and SCE Service Areas	Estimated Number of Dairy Cows (1)	Estimated Number of Dairy Cows being milked at any time (2)	Estimated Number of kWh Used per Month in county (3)	Estimated Monthly Cost with current rates (4) ($)	Estimated Annual Cost with current rates (4) ($)	Projected Monthly Cost with future rates (5) ($)	Projected Annual Cost with future rates (5) ($)
No. Calif.	1,007,400	886,512	35,460,480	2,869,810	34,437,723	3,979,976	47,759,712
So. Calif.	286,600	252,208	10,088,320	662,077	7,944,922	763,030	9,156,365
Totals	1,294,000	1,138,720	45,548,800	3,531,887	42,382,645	4,743,006	56,916,077
	Percent of Calif. Total		88%			Increase	34%
Other Utility Service Areas	175,600	153,528	6,181,120				
Calif. Totals	1,469,600	1,292,248	51,729,920				

(1) 1999 data. Source: CDFA Resources Directory 2000
(2) Herds estimated to be 12% dry at any time
(3) 40 kWh/cow/month. Source: UC Extension studies
(4) Current rate structure. Estimated from electricity service invoices. Includes all cost elements on a $/kWh basis. Varies by utility.
(5) Possible Rate Structure. Includes all cost elements on a $/kWh basis. Varies by utility.

Estimated monthly and estimated annual costs are based upon existing rate structures (those in effect in 1999 and 2000) and the projected estimated monthly and annual costs are based upon PG&E and SCE rate structures suggested in advice letters filings submitted to the PUC by the two utilities as directed in D.01-05-064. As in Appendix V, where county service areas are shared by two utilities (Kern shared by PG&E and SCE and Merced shared by PG&E and MEID) average rates have been used in this analysis. The number of cows have been held constant at reported 1999 levels. San Diego County (served by SDG&E) dairy cow numbers have been included in the table above (and the Appendix V) but current cost estimates and projected cost estimates are not included.

Table 2.5.3 shows that PG&E and SCE provide an estimated 88 percent of the total kWh used in California, so it is to be expected that any changes in their respective rate schedules will impact a very large proportion of the entire dairy sector.

An estimated $42.5 million is currently being spent annually by dairy producers for electric power delivered by PG&E and SCE. This could increase to $56.9 million under the proposed rates (a 34 percent increase). There are differences between northern and southern California, as well. Northern California, primarily served by PG&E could see electricity costs increase from $34.4 million to $47.8 million (a 39 percent increase). Southern California's costs, under the possible new rate structures, are projected to increase from $7.9 million to $9.2 million (a 15 percent increase).

Given that relatively high prices for electricity have been in place in California for quite sometime, it is very probable that all dairy operators have already made every attempt to be as efficient as possible in their use of electrical energy. Although there are energy saving concepts that could probably be incorporated at most dairies, the question of cost effectiveness always enters. As electricity prices increase, more of these improvements will become cost effective. However, the percentage reduction in electrical power use due to the more efficient system component must be greater than any anticipated percentage increase in price in order for the improvement to be cost effective.

Though not directly related to efficiencies in energy use, the analysis of dairy invoices illustrates that for each account at this one dairy, there will be a meter - and each meter incurs a monthly meter charge and a monthly customer charge whether or not much electricity passes through that meter. Possibly significant energy cost savings (not energy savings) could occur if dairy operators were permitted to have master meters installed. However, if there are significant distances between energy using motors, the installation of a master meter may not be physically possible. An additional attractive feature of having a master meter installed is that the dairy operator could balance downstream load to take advantage of time-of-day rate structures.

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Chapter 3

California Agricultural Electricity Rates

3.1. The Process of Setting Rates for Production Agriculture

Both historically and under current law, agricultural electricity rates have been subjected to the same California Public Utilities Commission (CPUC) regulatory processes that are used to set rates for other customer classes. Under this system, utility and intervenors' proposals are subjected to a quasi-judicial, adversarial process through which sufficient evidence and insight is intended to emerge upon which to base CPUC policies. The typical practice is for the utilities to "apply" to the CPUC for approval for specific actions, such as rate changes or the provision of new services or investments. The application is assigned to an administrative law judge (ALJ), who establishes a series of hearings at which CPUC staff and other interested parties can formally examine and critique the utility proposals, as well as offer alternative recommendations. Based on these hearings, the ALJ develops a proposed decision related to the application. This proposal is sent to the CPUC commissioners, who are free to render a decision as they deem appropriate.

Within this regulatory structure the CPUC has tended to provide agriculture with special treatment. For example, in cases where the investor-owned utilities (IOUs), particularly PG&E, requested double-digit increases in agricultural rates, the CPUC has capped actual price inflation at modest levels.[1] On numerous occasions regulators and legislators have mandated that studies be conducted to identify means to reduce agricultural rates.[2]

In the context of electricity, policymakers tend to view agriculture sympathetically for two important reasons. First, agriculture is considered a critical part of the state's economy, and food security in general is a high societal priority. Second, because of agriculture's small size relative to other customer classes, combined with its complex energy use patterns, it does not receive the same analytic scrutiny as other rate groups, and as a result there is a great deal of uncertainty related to the utilities' agricultural cost estimates upon which rates are set. As a

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[1] Agricultural rates may still be considered "high," but they are not notably different from residential rates, and do not, in the case of PG&E, reflect utility estimates of the costs imposed on the electrical system by growers. That is, analyses submitted as part of PG&E's deferred General Rate Case (A.99-03-014) indicate that the utility believes the marginal cost to serve the agricultural sector exceeds 17 cents per kilowatt-hour.

[2] For example, the Energy Commission conducted a series of studies in 1992 as directed by AB 2236. PG&E was ordered by the CPUC to submit a study in its 1999 GRC explaining the differences between its marginal cost estimates for agricultural customers and those developed by SCE and SDG&E.

result of these factors – the economic importance of the sector and ongoing uncertainty as to the cost the class imposes on utility systems – decision makers have been typically reluctant to impose significant price increases on farmers.

3.1.1. History of Setting Agricultural Rates

The CPUC generally allocates revenues among rate classes using the "equal percentage of marginal cost" (EPMC) methodology – an approach the CPUC initially adopted in a San Diego Gas and Electric Company's 1983 General Rate Case.[3] Under the EPMC method, the marginal cost of serving each customer is estimated by rate class. Total revenue requirements for the utility are then allocated among the classes based on their relative marginal cost shares.[4] However, because marginal costs have historically almost never been equal to the full revenue required to finance utility systems, the class-specific marginal-cost-derived revenues must be scaled upwards to equal the total revenue requirement.[5] This is done by allocating class revenue requirements in proportion to their marginal-cost-based revenues (e.g., EPMC).[6]

Since the adoption of EPMC, the CPUC has made a number of changes to agricultural rate policies. Of particular importance has been the consistent implementation of caps on the amount of allowable increases in agricultural rates, particularly in PG&E's service territory. That is, facing the prospect of double-digit annual increases in PG&E's agricultural rates, over the last decade the CPUC has consistently capped agricultural prices at rates that are less than the utility's estimates of class-specific equal percentage of marginal cost. This has occurred in every

[3] D.83-12-065.

[4] This is a simplified application of "Ramsey pricing." Ramsey pricing is a "second best" of allocating costs when average costs exceed marginal costs, which is assumed to be the case with energy utilities. It uses marginal costs and demand elasticities for each customer group to assign relative shares of average costs.

[5] Until recently the EPMC factor in both PG&E's and SCE's service territory has been almost two (average costs are almost double marginal costs to generate the necessary revenue requirements). This was chiefly because of the high costs associated with generating facilities, such as nuclear power plants and "qualifying facilities" (i.e., independently-owned generating plants which provided power to the utilities under CPUC-mandated contracts). However, SCE's current estimate of its EPMC multiplier in its now deferred Post Transition Rate Design filing (A.00-01-009) is close to one. SCE is proposing a new methodology using an "engineering elasticity" factor to allocate average costs above marginal costs at the distribution component level rather than at the system level, as is done with EPMC. SCE is proposing to allocate the distribution costs above per-customer marginal costs by dividing the total distribution costs between a "design demand" charge, which varies with customer demand, and a "grid charge" that represents the average remaining cost, after the design demand cost, allocated to the average customer in that rate class. The EPMC methodology, in contrast, totals the marginal costs within each rate class first, and then allocates the total cost responsibility based on the relative magnitudes of the marginal costs incurred by each rate class.

[6] "Marginal-cost-based" revenues are the revenues that would be collected if rates were based only on the marginal costs of providing service, without recovering overhead, administrative, or historic "sunk" costs.

PG&E GRC since the 1990 Test Year case. For example, based on the EPMC methodology, in its 1996 GRC PG&E estimated that the agricultural class should be subjected to rate increases as high as almost 60 percent. However, as noted above, for a number of reasons the CPUC has not acted on these proposed prices hikes, and instead has approved only modest increases in agricultural rates. Still, even with these rate hike moderations, California's agricultural electricity rates continue to remain among the highest in the nation.

In addition, since the mid-1990s, both PG&E and SCE have offered agricultural "bypass rates" as a means of encouraging growers to continue to use electricity, as opposed to turning to an alternative fuel for pumping water, such as diesel or natural gas. Such bypass can shift revenue requirements to other customers, and can lead to significant local air quality impacts. Under these rates growers who can demonstrate that they have a viable, cost-effective source of alternative energy can obtain reductions in their otherwise applicable tariff. However, bypass-based prices are never pegged below the marginal costs to serve the customer.

3.1.2. General Process for Establishing Rates Today

As a result of electric industry restructuring, the IOUs' primary service responsibility is providing distribution and related customer services. Likewise, the CPUC's oversight of the IOUs, now more commonly referred to as "utility distribution companies" (UDCs), is mostly related to these systems. Although there are a plethora of ongoing regulatory proceedings currently examining various elements of the electric industry – many of which will influence the shape of the future market – there are three major proceedings through which the distribution system is currently regulated.

3.1.2.1. General Rate Cases

General Rate Cases (GRCs) have historically been used to establish the UDCs' revenue requirements (e.g., the amount of funds legitimately needed to operate the system in a cost-effective and reliable manner), and to determine how these funds should be allocated to different customer classes. In this respect GRCs have traditionally been separated into two phases. In phase one, the utilities propose the total budget they require to provide a certain bundle of services (i.e., "the size of the utility pie"), as well as their estimates of the marginal costs various customer groups impose on the system by their energy use. In phase two, the UDC recommends the portion of required revenues assigned to each customer class (i.e., the size of their slice of the pie,) and how this responsibility should flow through to rates.[7]

[7] "Rate Design Windows" (RDW) are a derivative of the phase two portion of a GRC, and typically are given the

Although as with all ratepayers the agricultural sector has an interest in limiting the overall size of the utility pie (i.e., keeping total revenue requirements low), most agriculture-specific issues tend to emerge in the GRC's second phase. Likewise, both because of its geographic scope and generally higher rates, PG&E's rate cases have typically been more controversial than SCE's or San Diego Gas and Electric Company's. Because the CPUC has adopted other regulatory schemes, such as Performance-Based Ratemaking for the two utilities, SCE has not had a GRC since 1994, and SDG&E has not had one since 1991. All three utilities are scheduled to file a new GRC in 2001 or 2002.

Through the past two decades, PG&E has consistently proposed significant increases in agricultural rates. These proposals have been based on the UDC's estimate that the agricultural class imposes high costs on the utility system, and as a result should have concomitantly high rates. PG&E's high cost estimates for agriculture – particularly small growers – are principally based on analyses which indicate that most growers represent "low load factor" customers (i.e., high peak loads versus average usage, which translates into little electricity usage overall relative to the fixed investments required to serve them). That is, relative to other customer classes agriculture has fewer units of use on which to spread the necessary costs of service.

However, agricultural interests, notably the Agricultural Energy Consumers Association (AECA), and the California Farm Bureau Federation (CFBF), have asserted that PG&E's cost estimates have been fundamentally flawed, as they do not accurately separate agricultural energy use from other classes, and do not account for agricultural load diversity. These issues remain unresolved and possibly, within the limited analytic resources available, unresolvable. In the 1999 GRC, PG&E proposed both to allow growers to aggregate load, so as to better capture load diversity,[8] and to merge agriculture with the commercial class, which is estimated to have lower aggregate marginal costs of service, as a means of reducing average agricultural rates. However, proceedings in the second phase of the 1999 GRC have been deferred while the CPUC addresses the broader energy crisis issues.

Currently, PG&E and SCE are scheduled to file General Rate Case notices of intent

same application number.

[8] Unlike most customers, each agricultural pump generally is assigned a different account number by the UDCs, and is treated like a separate customer. It would be as if a residence had a different electricity account for each plug in the house. As a result, under existing practices the utilities do not capture variations in pump usage within a given operation. That is, while one farm, ranch, or water district might have 200 or more pumps, these pumps are rarely run simultaneously. This "load diversity" serves to reduce the amount of coincident demand agriculture places on the utility system. If not adequately accounted for, as alleged by agricultural intervenors, estimated marginal costs of the agricultural class could be too high.

(NOI) this summer, in prelude to formal applications late in 2001. PG&E will be filing for a 2002 "test year," and SCE for a 2003 test year. A test year is the year in which the analysis is based. The CPUC has not yet ruled on the final schedule for these applications, because of the energy crisis and an expected glut of significant applications from all of the energy utilities in the next two years. In addition, the CPUC has yet to rule on whether it will continue with PG&E's 1999 Test Year GRC Phase II application, in which rates would be designed to collect the revenue requirements from the Phase I decision (D.00-02-046).

3.1.2.2. Performance-Based Ratemaking

As part of the restructuring process, the CPUC has encouraged the UDCs to shift from cost-plus regulation, in which, as discussed above, every three years the utilities request approval for a particular revenue level, to Performance-Based Ratemaking (PBR), in which ongoing incentives are provided to reduce utility revenue needs. Under PBR, the utilities receive an adjudicated revenue level, which increases annually based on an economic index that includes inflation,[9] productivity gains and other key factors. The utility is then eligible to obtain a portion of additional cost savings it generates, with ratepayers also receiving a share of any cost reductions. PBRs are intended to provide automatic incentives for the utilities to constantly seek ways to increase their operational efficiencies.

SCE and SDG&E currently operate under PBRs. PG&E has requested similar treatment, but the CPUC recently deferred its pending application beyond another GRC cycle. PBR proceedings typically result in few class-specific issues, but instead, as indicated above, focus on aggregate revenue levels and the development of appropriate incentives for superior utility performance.

3.1.2.3. Post-Transition Ratemaking

Under AB 1890 bundled rates are frozen until either the utilities are fully paid for their "stranded assets,"[10] or by April 1, 2002, whichever occurs sooner.[11] Each of the utilities must file a post-transition rate design application, which, similar to a GRC, outlines proposed revenue levels, class-specific revenue responsibilities, and rate structures for implementation after the rate freeze ends.

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[9]Typically a Consumer or Producer Price Index.

[10]Chiefly facilities (e.g., nuclear plants) or power purchase contracts with other energy suppliers that resulted in higher than market energy prices.

[11]Public Utilities Code Section 368(a)

SDG&E's rate freeze ended in the summer of 1999, and the utility proceeded through the PTR process by using a RDW filing (A.91-11-024), with a decision adopted in October 2000. However, the unexpected supply and demand conditions resulted in dramatic increases in SDG&E's rates, and, as a result, both the CPUC (D.00-08-037) and the State Legislature (AB 265) have adopted interim rate policies for the utility's service territory.

SCE has filed its post-transition rate design (PTRD) proposal (A.00-01-009), which SCE has petitioned to be withdrawn, addresses other issues in the energy crisis. Under this application, the utility proposed to change its rate structure to shift costs towards fixed, rather than variable, rates. That is, Edison proposed to increase monthly charges, and reduce demand-related rates. SCE's approach is based on three factors: (1) since a portion of the distribution system is "fixed" (i.e., does not vary with customer use), ratepayers should likewise pay fixed fees to support these investments. For example, the quantity of telephones used by the utility does not change depending on how much electricity is used, but rather is dependent on the number of customers; (2) by collecting fixed fees the utility will better secure ongoing revenue, thereby reducing its financial risks; and (3) the use of fixed fees will tend to shift costs from large to small customers. Since, under restructuring larger customers are more likely to have a choice of alternative energy service providers, a balance towards fixed fees will improve Edison's ability to compete in the emerging market.

Prior to the rise in PX prices in the summer of 2000, the effect of Edison's proposals on average electricity rates would have been offset by steep reductions in CTC charges. However, under current conditions almost customers would see price increases once the rate freeze ends.

SCE's PTRD proposals, combined with likely higher energy prices, would result in increased electricity bills for the majority of growers, while some customers may actually benefit. Precise bill impacts would depend on the particular rate schedule and use patterns.[12] For example, while almost 25 percent of high-load factor PA-1 customers would see reductions in the distribution portion of their bills, more than 40 percent of customers with similar characteristics would experience an increase in that portion. Likewise, all low and medium load factor TOU-PA-5 customers would see a large increase in that portion of their bills if Edison's proposals are adopted by the CPUC.[13]

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[12] Craig M. Keen, Southern California Edison, "Post-Transition Rate Design Proposals, Proposed Tariffs," A.00-01-09, Exhibit SCE-5, July 2000.

[13] Bruce A. Reed, Senior Attorney, SCE, Letter to Steven Moss, M.Cubed, Data Response, A.00-01-009, October 19, 2000.

The CPUC will rule during the summer of 2001 on how to dispose of this application. Currently the proceedings are suspended. It is likely that this application will be superceded by SCE's 2002 Test Year GRC filing.

3.1.2.4 Rate Stabilization Plans

In November 2000, PG&E (A.00-11-038) and SCE (A.00-11-056) applied to the CPUC for rate relief due to the extraordinary increase in wholesale power costs. These "rate stabilization plans" were intended to recover past procurement costs since May 2000, and to fund future power purchases.

The CPUC authorized a one cent per kilowatt-hour surcharge applied to all customers on a level basis in January 2001.[14] The Legislature authorized the California Department of Water Resources (CDWR) to take over power purchasing responsibilities for the utilities January 17.

The CPUC then determined March 27 that the utilities were responsible for past power procurement costs under the terms of restructuring,[15] that CDWR was entitled to a portion of the existing rates collected by the utilities,[16] and that an additional three cent surcharge was required to fund going-forward power purchases.[17] The rate proceedings then moved to an accelerated second phase where the revenue responsibilities are allocated and the rates designed. The CPUC issued its on how to allocate revenue responsibility among ratepayers and how to design rates on May 15.[18] The CPUC determined that "in response to the Governor's proposal to recognize the unique role agriculture plays in California's and the nation's economy, we cap agricultural rate increases at a range of 15-20 percent, depending on the agricultural customer tariff."[19] This is in contrast to the 45 percent average increase for most residential, commercial and industrial customers. Agricultural rate increases were exempted in large part because agricultural pumping costs are likely to increase significantly this summer due to drought.[20] The CPUC imposed the rate increase entirely on the energy charge portion of the tariffs. Given that agricultural rates have substantial fixed monthly charges, this means that the energy charge will rise significantly more than the "average" rate increases adopted by the CPUC.

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[14]D.01-01-018.

[15]D.01-03-082, based on Public Utilities Code Section 368.

[16]D.01-03-081.

[17]D.01-03-082.

[18] D.01-05-064.

[19] Ibid., p. 4.

[20] See discussion in Chapter 2 estimating agricultural demand response to water conditions and supplies.

3.2 Agricultural Rates in Comparison to California Commercial Customers

Although charges vary by the level and characteristics of an individual customer's load, PG&E electric rates for agricultural customers have historically been higher than the rates charged commercial customers. Agriculture's higher rates are partially the result of the imposition of demand charges, which are designed to pay for the portion of fixed distribution capacity used by each customer. Commercial customers pay more of their distribution costs in the "energy" or volumetric component of the rate. In addition, agricultural customers have more meters on their total load, each meter incurs monthly "customer" charges that do not vary with load or usage. Thus, agricultural customers generally pay higher customer charges per unit of energy than commercial customers.

However, as part of its 1999 General Rate Case, PG&E proposed to move small and medium agricultural accounts to the small and medium light and power, or commercial, class. If this proposal is adopted by the CPUC only the largest farm accounts will remain in the agricultural class, under the AG-5 schedule.

The small and medium light and power groups consist of amalgamations of many different kinds of customers. For example, laundries, convenience stores, print shops, and even some agricultural-related end-uses might all be included in this same rate category. While these customers may be in the same class, they exhibit a wide diversity of energy consumption and load factors. Table 3.2.1 shows the number and proportion of the largest end-users in the proposed amalgamated rate groups.[21]

Table 3.2.1
Comparison of Major Industry Types in PG&E Proposed Merged Rate Groups

		Small Light & Power		***Medium Light & Power***	
Classification	**SIC**	**Number of Accounts**	**Percent of Group**	**Number of Accounts**	**Percent of Group**
Agriculture	00-09	62,114	13%	13,274	18%
Transportation & Public Utilities	40-49	52,203	11%	5,773	8%
Retail Trade	52-59	60,614	13%	21,569	29%
Finance Insurance & Real Estate	60-67	35,020	7%	7,434	10%
Services	70-87	106,172	23%	13,172	17%
Other	99	95,886	20%	5239	7%
Total in Merged Rate Group		470,824	100%	75,376	100%

PG&E data demonstrate a wide range of consumption for the current small and medium light and power groups. Summary statistics of the billing frequency distributions are shown in Table 3.2.2. These data indicate that the *range* of annual consumption is the same for both light

[21] PG&E, *1999 Test Year B Phase 2 Revenue Allocation Consolidated*, Application Number 99-03-014, Exhibit PG&E-3, August 18, 2000.

and power groups whether or not the agricultural schedules are included. For both groups, the mean annual consumption is slightly reduced by the amalgamation.

Table 3.2.2
Summary Statistics for Kilowatt-Hour Consumption
Before and After Proposed PG&E Amalgamation

	Minimum	Maximum	Mean	Stan. Dev.	Stan. Error
Small L&P	1	3,086,277	17,101	136	0.008
Combined w/Agriculture	1	3,086,277	16,228	125	0.0077
Medium L&P	1	5,910,800	281,432	6,633	0.0236
Combined w/Agriculture	1	5,910,800	246,220	5,584	0.0227

The existing light and power groups posses a broad range of load factors. The majority of the Small Light and Power class have load factors of under thirty percent, while the Medium Light and Power class more typically have load factors between ten and fifty percent. However, there is a broad category where both rate groups overlap. As a result, *on average,* the Medium Light and Power group members *tend* to have higher load factors than members of the Small Light and Power group.

The members of the amalgamated Small Light and Power Group will have a slightly lower load factor on average than the current group. However, the difference is small, with the majority of the group′s load factors remaining between zero and thirty percent. Similarly, members of the amalgamated Medium Light and Power group have a slightly lower load factor on average than the current group, but once again the difference is small.

Finally, as indicated in Table 3.2.3, folding agricultural customers into either the Small or Medium Light and Power groups would result in unnoticeable price changes to the existing customers in those classes. Small Light and Power customers would experience an approximately one-quarter of one cent per kWh increase, while the rate increase for Medium Light and Power ratepayers would be even less B under one-tenth of one cent.

Table 3.2.3
PG&E's Proposed Total Average Rate
(Cents per kWh)

Rate Group	Without Ag	With Ag.	Difference
Small Light and Power	10.76	11.04	0.28
Medium Light and Power	7.18	7.26	0.08

Southern California Edison Company′s agricultural rates tend to be *lower* than the rates charged the commercial class. For example, on average agricultural and pumping customers pay 9.6 cents per kWh, compared to 10.6 cents/kWh for the small light and power class.[22] Edison′s agricultural rates are lower than PG&E′s for a variety of reasons, not least of which is that SCE

[22] SCE, Post Transition Rate Design, A.00-01-009, July 2000.

includes large pumping customers, who have relatively low marginal costs, in the agricultural class, while PG&E considers places these customers in the large power category.

3.3 Comparison of Agricultural Rates in California and Other Western States

Electricity rates, and the resulting costs of operation, are significant components in the overall costs of agricultural operations in California. Costs of electricity account for four or five percent of overall costs incurred by agricultural producers, with the percentage rising to 7 to 10 percent for row and vegetable crop producers.

Electricity invoices consist of three components: energy charges; demand charges; and customer charges. Energy charges vary by season (summer vs. winter) and by time of day (peak vs. off peak). Demand charges can also vary by season and time of day. The importance of each component in a typical invoice varies with the demand (load) placed on the system by an individual installation - as the demand (kilowatts) increases, the electricity proportion of the typical invoice decreases.

Changes in electric rates between those in effect in 2000 and 2001 will be addressed by two approaches in the following two sections. The first approach is to present percentage changes in the rates charged by PG&E and SCE and the second will be to present changes in representative annual costs for electric service that are associated with the rate changes.

3.3.1 Rate and Cost Comparisons for California Utilities

Tables 3.3.1 and 3.3.2 summarizes recent changes in electricity rates charged agricultural customers by the two utilities serving most of California's agricultural production areas. Four PG&E rate structures and three SCE rate structures are shown. "Previous" rates were in effect through the year 2000 and "new" rates will come into effect in June 2001.

Table 3.3.1
Comparison of Changes in PG&E Rate Structures
Changes in Rates Shown as Ratio of New Rates to Previous Rates

	Previous 1) Rate or Charge	New 2) Rate or Charge	New/ Previous
PG&E's AG 1B rate			
Energy per kWh	$0.11984	$0.15571	1.299
Summer $/kW	$2.90	$2.90	
Winter $/kW	$1.75	$1.75	
Customer $/mo.	$16.00	$16.00	
PG&E's AG VB rate			
Energy per kWh			
Summer on peak	$0.24935	$0.28784	1.154
Summer off peak	$0.07737	$0.11586	1.497
Winter partial peak	$0.07764	$0.11613	1.496
Winter off peak	$0.06172	$0.10021	1.624
Demand $/kW			
Summer on peak	$2.75	$2.75	
Summer max	$2.90	$2.90	
Winter max	$1.75	$1.75	
Customer $/mo.	$16.00	$16.00	
Meter $/mo.	$6.00	$6.00	
PG&E's AG 4B rate			
Energy per kWh			
Summer on peak	$0.20711	$0.24489	1.182
Summer off peak	$0.06499	$0.10277	1.581
Winter partial peak	$0.07182	$0.10960	1.526
Winter off peak	$0.05710	$0.09488	1.662
Demand $/kW			
Summer on peak	$2.75	$2.75	
Summer max	$2.90	$2.90	
Winter max	$1.75	$1.75	
Customer $/mo.	$16.00	$16.00	
Meter $/mo.	$6.00	$6.00	
PG&E's AG 5B rate			
Energy per kWh			
Summer on peak	$0.14294	$0.17247	1.207
Summer off peak	$0.04088	$0.07041	1.722
Winter partial peak	$0.04661	$0.07614	1.634
Winter off peak	$0.03706	$0.06659	1.797
Demand $/kW			
Summer on peak	$2.70	$2.70	
Summer max	$6.55	$6.55	
Winter max	$4.40	$4.40	
Customer $/mo.	$16.00	$16.00	
Meter $/mo.	$6.00	$6.00	

Table 3.3.2
Comparison of Changes in SCE Rate Structures
Changes in Rates Shown as Ratio of New Rates to Previous Rates

	Previous 1) Rate or Charge	New 2) Rate or Charge	New/ Previous
SCE's PA-1 rate			
Energy per kWh	$0.09172	$0.12247	1.335
Load $/kW	$2.05	$2.05	
Customer $/mo.	$17.65	$17.65	
SCE's TOU PA-B rate			
Energy per kWh			
Summer on peak	$0.11229	$0.17408	1.550
Summer mid peak	$0.07256	$0.09756	1.345
Summer off peak	$0.03952	$0.06452	1.633
Winter peak	$0.08503	$0.11003	1.294
Winter off peak	$0.03952	$0.06452	1.633
Demand $/kW			
Facilities related	$2.85	$2.85	
Peak	$9.00	$9.00	
Customer $/mo.	$42.80	$42.80	
SCE's TOU PA-5 rate			
Energy per kWh			
Summer on peak	$0.07947	$0.13545	1.704
Summer mid peak	$0.05142	$0.07542	1.467
Summer off peak	$0.04283	$0.06683	1.560
Winter peak	$0.06022	$0.08422	1.399
Winter off peak	$0.04920	$0.07320	1.488
Demand $/kW			
Facilities related	$2.85	$2.70	
Peak	$9.00	$6.55	
Customer $/mo.	$40.70	$40.70	

Notes
1) Previous: in effect through 2000
2) New: to be in effect in 2nd half of 2001

Over the years, growers have adjusted their usage patterns to avoid peak period use whenever possible. Increases in summer peak rates, though very significant, will not have as great an impact on annual costs as will increases in summer off-peak rates.

There are differences between the two California utilities' rate structures. PG&E rates for consumers of larger amounts of power (AG 4B and AG 5B) show significant year-to-year changes in summer peak charges (approximately 20 percent) with even greater increases (approximately 65 percent) in summer off-peak prices. PG&E's winter rates show large (50 to 80 percent) increases, as well. SCE has taken an alternative approach with respect to its rate structures for consumers of larger quantities of electricity (PA-B and PA-5 rates). Summer peak rates have risen by 72 percent in the PA-B rate and by 230 percent in the PA-5 rate. Summer mid-peak and off-peak rates increased by an average of about 44 percent. SCE's winter rates did not increase as much as did PG&E's winter rates, but increases still average over 40 percent.

The impact of changing rate structures can be seen more clearly by looking at the effects of changing rates on monthly and annual bills paid by consumers of electricity. In order to accomplish this part of the analysis, illustrative 1999 usage patterns from actual dairy production accounts were assembled and monthly invoices were examined and directly correlated with usage of electricity. This formed the basis for the bills associated with the "previous" rates. Then, rates were increased to reflect the "new" rate structures. Figures 3.3.1 and 3.3.2 illustrate the results of this analysis. Figures for other rate structures are in Appendix VI.

Figure 3.3.1

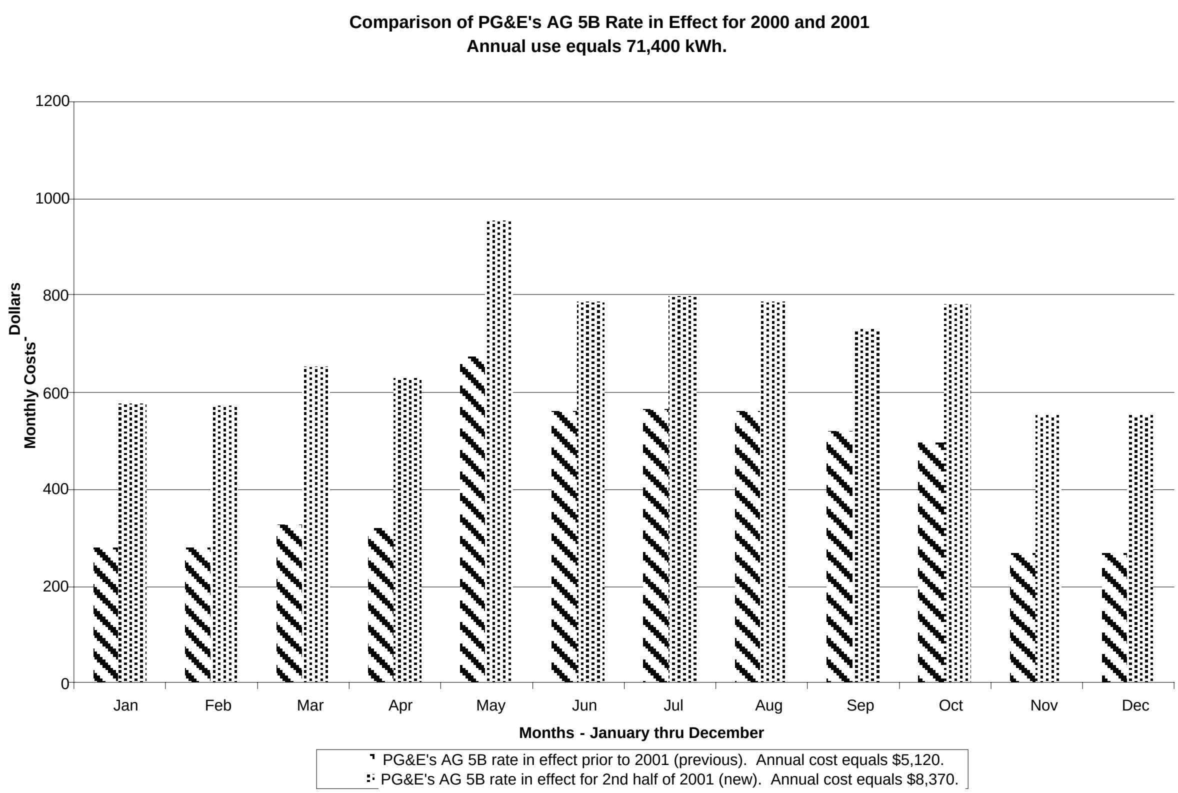


Figure 3.3.2

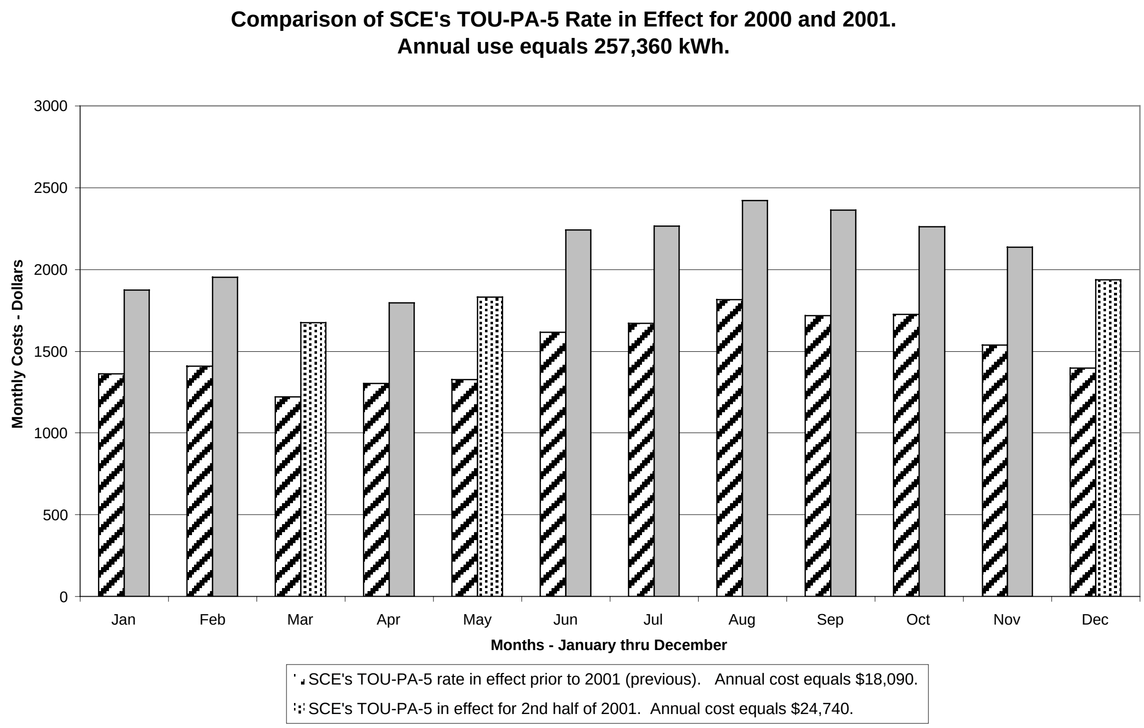


Table 3.3.3 summarizes the probable effect of changes in rate structures on annual costs of operation for representative accounts.

Table 3.3.3
Comparison of Annual Costs for Various Rate Schedules
Annual Costs for Representative Accounts
Shown as Ratio of Annual Costs

	New cost/ Previous cost
PG&E's AG 1B rate	1.26
PG&E's AG VB rate	1.45
PG&E's AG 4B rate	1.51
PG&E's AG 5B rate	1.63
SCE's PA-1 rate	1.25
SCE's TOU PA-B rate	1.41
SCE's TOU PA-5 rate	1.37

Previous cost: based upon rates in effect thru 2000
New cost: based upon rates in effect in 2nd half of 2001

"New" costs relative to "previous" cost column shows significant increases in annual costs under all rate structures. The low demand rates (AG 1B and PA-1) had cost increases of approximately 25 percent. The mid-range demand rates (AG VB, AG 4B and PA B) had cost increases averaging approximately 45 percent. The high demand rates (AG 5B and PA-5) had cost increases of 51 and 35 percent, respectively.

3.3.2 Rate and Cost Comparisons between Utilities in the Western States

Electricity rates, and the resulting costs of operation, are significant components in the overall costs of agricultural operations in the western states because of the need to irrigate crops. Agricultural producers in most of the western states cannot depend upon rainfall during the production year.

Comparison of unbundled distribution costs among utilities is means of comparing how efficiently the utilities are providing electrical service for agricultural pumping. While generation and transmission costs are largely beyond a utility's control, distribution costs are controlled by the utility as discussed below. The preferred method for comparison would examine the distribution of customer demand and energy use for each utility area, and the comparison made among customers at selected points in the distributions, e.g., the 25th, 50th, and 75th percentiles, for average rates and total bills. Unfortunately, the distributions of billing determinants are not readily available from utilities other than PG&E and SCE. For this reason, a typical per kWh distribution cost associated with 131 kW of demand and 2000 hours per year are used for comparison purposes. a comparison was made using only the distribution-related cost components for agricultural pumping rates for SCE PG&E, Modesto Irrigation District (MID), Arizona Public Service (APS), Salt River Project (SRP) and Tillamook Utility District (TPUD).

An initial comparison of PG&E's and SCE's rates to out-of-state utilities' and irrigation districts gives the impression that PG&E's and SCE's are substantially higher. However, some of the differences in rates arise from at least two factors:

- PG&E and SCE ratepayers are paying for "stranded assets"—uneconomic investments in nuclear power, and contracts with cogeneration and renewable energy providers called "qualifying facilities" or QFs, which do not burden most of the out-of-state utilities and irrigation districts.
- The municipal and Northwest utilities have access to low-cost, subsidized federal power, or to large amounts of previously-developed hydropower which are not available to PG&E and SCE.

The meltdown in the power market has reverberated beyond California as well. PG&E and SCE customers already have seen rates increase an average of four cents per kilowatt-hour since January 2001, again making the state's rates the highest in the nation. However, rates are increasing dramatically elsewhere in the West as well. For example, the federal Bonneville Power Administration is proposing to increase its wholesale rates by as much as 150 percent to

4.5 cents per kilowatt-hour by October 2001. How California's municipal utilities will come out is uncertain as well, as that they are not completely shielded from the market conditions. At this time, no conclusions can be made about the relative costs of generation among the Western utilities.

Comparing utility rates on an "apple-to-apple" basis requires making several assumptions and disentangling complex interrelationships within each utility's rates. Based on this reality, the proper comparison is among the costs associated with "wires" services—the transmission and distribution of electricity, and the provision of public purpose programs such as low-income support and energy efficiency. A California grower cannot buy the generation component of their power from Bonneville Power Administration in Oregon for the obvious reason that the grower cannot relocate his entire operation to that state. On the other hand, the grower might be able to expect PG&E or SCE to manage their system to deliver power at the costs incurred by Sierra Pacific or Arizona Public Service Companies, or even that irrigation districts could come in and provide public power services. But in either case, the grower would be a customer of a utility that has to purchase most of its power in the open market at substantially the same costs as other California utilities. The proper rate comparison would show what the rates would be for each utility if it purchased energy at the same cost, paid off the same stranded assets, but incurred distinct local "wires" costs.

Utilities outside of California appear to have generally lower unbundled distribution costs. The SCE neighbors SRP and APS have distribution cost of 14 to 16 mills. In the PG&E territory, MID had unbundled tariffs of 11 and 13 mills for their P-4 and P-3 rates, respectively. These are notably low because they also include transmission costs, as these could not be broken out. A rough approximation of the TPUD-Farm tariff yields a distribution tariff of about 19 mills.

3.3.2.1 Electricity Rate Components for Selected Utilities

Electricity rate structures to be used by utilities serving production agriculture during the 2001 crop year are included in this summary. Recent changes in electricity charges imposed by the two larger utilities serving California agriculture have been focused entirely on the energy component (demand charges and customer charges are unchanged) - and it is the California rate structures in effect as of June 2001 that are included.

Tables 3.3.4 through 3.3.6 summarize the electricity rates charged agricultural customers by the utilities. Table 3.3.4 focuses upon rate structures where the demand is relatively low (< 35 kW). Tables 3.3.5 and 3.3.6 focus upon higher levels of demand (35 < kW < 100 and > 100 kW, respectively). Eleven different rate structures are shown in Table 3.3.4 and 12 different rate structures are shown in the other two tables. Some utilities do not offer as many rate structures (for varying loads) for agricultural consumers as do the California-based utilities. Necessarily, there is some overlap of rate schedules between the tables.

In the western states, the largest proportion of electricity used in agriculture is used for pumping irrigation water during summer months. Because most of California utilities' rate structures discourage peak period consumption, many California producers have set up their irrigation schedules to avoid peak time periods, whenever possible. Summer off-peak rates charged by California's primary suppliers of electricity are significantly greater than peak period rates charged by other utilities. Some utilities (e.g., Portland General Electric) employ declining block rate structures for customers who use larger amounts of electricity each month. Demand (load) charges assessed by California's primary suppliers are also greater than those charged by out-of-state utilities. Appendix VI contains copies of tariff sheets used by various utilities shown in the tables.

Table 3.3.4
Comparison of Rate Structure Components by Utility < 35 KW
all to be in effect in 2nd half of 2001

	Customer	Facilities	Rate Seasons		Demand (Load) Charge			Energy Charge				
								Summer			Winter	
	Charge	Charge	Summer	Winter	Summer Peak	Summer	Winter	Peak	Part. Peak	Off Peak	Part. Peak	Off Peak
	($/mo.)	($/mo.)			($/kW)	($/kW)	($/kW)	($/kWh)	($/kWh)	($/kWh)	($/kWh)	($/kWh)
PG&E's AG 1B rate	$16.00		May-Oct.	Nov.-Apr.		2.90	1.75	0.15571		0.15571	0.15571	0.15571
PG&E's AG VB rate	$22.00		May-Oct.	Nov.-Apr.	2.75	2.90	1.75	0.28784		0.11586	0.11613	0.10021
SCE's PA-1 rate	$17.65		June-Oct.	Nov.-May		2.05	2.05	0.12247	0.12247	0.12247	0.12247	0.12247
Modesto ID's Sch. P-3	$6.29		May-Sept.	Oct.-Apr.	0.63	0.63	0.63		1st 5K kWh @ .0715		1st 5K kWh @ .0635	
									> 5K kWh @ .0626		> 5k kWh @ .0557	
Turlock ID's FC rate	$10.00		June-Nov.	Dec.-May	0.18	0.18	0.18	0.08890	0.08890	0.08890	0.08400	0.08400
SMUD's A-763 rate	$11.60		May-Oct.	Nov.-Apr.				0.15343		0.07922	0.10368	0.08723
Portland GE's Sch. 31	$12.00								1st 5K kWh @ .06237		1st 5K kWh @ .06237	
									> 5K kWh @ .04151		> 5K kWh @ .04151	
Pacific P & L's OR Sch. 25		15.25 for 1st				0/kW for kW < 15			1st 3K kWh @ .06396		1st 3K kWh @ .06396	
		15kW +				2.33/kW for kW > 15			> 3K kWh @ .04660		> 3K kWh @ .04660	
		.7/kW if more										
Tillamook PUD's farm rate	$13.00							0.05180	0.05180	0.05180	0.05180	0.05180
Tucson Elec Pwr GS-10	$13.24		May-Oct.	Nov.-Apr.					1st 3.4K kWh @ .113695		1st 3.4K kWh @ .113695	
									> 3.4K kWh @ .100343		> 3.4K kWh @ .093772	
Wells REC rate code 0005		$10.25						0.05700	0.05700	0.05700	0.05700	0.05700

Table 3.3.5
Comparison of Rate Structure Components by Utility 35 to 100 KW
all to be in effect in 2nd half of 2001

	Customer Charge ($/mo.)	Facilities Charge ($/mo.)	Rate Seasons Summer	Rate Seasons Winter	Demand (Load) Charge Summer Peak ($/kW)	Demand (Load) Charge Summer ($/kW)	Demand (Load) Charge Winter ($/kW)	Energy Charge Summer Peak ($/kWh)	Energy Charge Summer Part. Peak ($/kWh)	Energy Charge Summer Off Peak ($/kWh)	Energy Charge Winter Part. Peak ($/kWh)	Energy Charge Winter Off Peak ($/kWh)
PG&E's AG 4B rate	$22.00		May-Oct.	Nov.-Apr.	2.75	2.90	1.75	0.24		0.10277	0.1096	0.09488
SCE's TOU PA-B rate	$42.80		June-Oct.	Nov.-May	9.00	2.85	2.85	0.17408	0.09756	0.06452	0.11003	0.06452
Wells REC rate code 0004		240/yr.	Apr.-Oct.	Nov.-Mar.		3.89	3.89	0.04200	0.04200	0.04200	0.04660	0.04660
Surprise Valley Sch. PA			Mar.-Oct.			2.67	2.67	0.03650	0.03650	0.03650	0.03650	0.03650
Modesto ID's Sch. P-3	$6.29		May-Sept.	Oct.-Apr.	0.63	0.63	0.63		1st 5K kWh @ .0715		1st 5K kWh @ .0635	
									> 5K kWh @ .0626		> 5k kWh @ .0557	
Turlock ID's FD rate	$40.00		June-Nov.	Dec.-May	6.50	6.50	6.00	0.05250	0.05250	0.05250	0.04900	0.04900
SMUD's A-564 rate	$70.00					2.80	2.00		1st 8.75K kWh @ .16442			1st 8.75K kWh @ .10396
									>8.75K kWh @ .08461			>8.75K kWh @ .08746
Portland GE's Sch. 31	$20.00	0/kW for kW < 30				0/kW for kW < 30			1st 5K kWh @ .06049			1st 5K kWh @ .06049
(demand level II)		.5/kW for kW > 30				4.5/kW for kW > 30			> 5K kWh @ .03530			> 5K kWh @ .03530
Pacific P & L's OR Sch. 41			Apr.-Nov.	Dec.-Mar.		< 50 kW @ 10/kW		0.049980	0.049980	0.049980	0.074250	0.074250
						50 < kW < 300 is 200 + 6/kW						
						Load charge is annual						
Sierra Pacific's IS-2 rate								0.04451	0.04451	0.04451	0.04451	0.04451
Salt River Proj.'s E-47 rate	$16.00		May-Oct.	Nov.-Apr.		3.45	1.30	0.05580	0.05580	0.05580	0.0419	0.0419
Tucson Elec. Pwr's GS-31			May-Oct.	Nov.-Apr.				0.05150	0.05150	0.05150	0.050208	0.050208

Table 3.3.6
Comparison of Rate Structure Components by Utility > 100 KW
all to be in effect in 2nd half of 2001

	Customer	Facilities	Rate Seasons		Demand (Load) Charge			Energy Charge				
					Summer			Summer			Winter	
	Charge	Charge	Summer	Winter	Peak	Summer	Winter	Peak	Part. Peak	Off Peak	Part. Peak	Off Peak
	($/mo.)	($/mo.)			($/kW)	($/kW)	($/kW)	($/kWh)	($/kWh)	($/kWh)	($/kWh)	($/kWh)
PG&E's AG 5B rate	$22.00		May-Oct.	Nov.-Apr.	2.70	6.55	4.40	0.17247		0.07041	0.07614	0.06659
SCE's TOU PA-5 rate	$40.70		June-Oct.	Nov.-May	6.55	2.70	2.70	0.13545	0.07542	0.06683	0.08422	0.07320
Wells REC rate code 0004		240/yr.	Apr.-Oct.	Nov.-Mar.		3.89	3.89	0.04200	0.04200	0.04200	0.04660	0.04660
Surprise Valley Sch. PA			Mar.-Oct.			2.67	2.67	0.03650	0.03650	0.03650	0.03650	0.03650
Modesto ID's Sch. P-3	$6.29		May-Sept.	Oct.-Apr.	0.63	0.63	0.63		1st 5K kWh @ .0715		1st 5K kWh @ .0635	
									> 5K kWh @ .0626		> 5k kWh @ .0557	
Turlock ID's FD rate	$40.00		June-Nov.	Dec.-May	6.50	6.50	6.00	0.05250	0.05250	0.05250	0.04900	0.04900
SMUD's A-564 rate	$70.00					2.80	2.00		1st 8.75K kWh @ .16442			1st 8.75K kWh @ .10396
									>8.75K kWh @ .08461			>8.75K kWh @ .08746
Portland GE's Sch. 31	$20.00	0/kW for kW < 30				0/kW for kW < 30			1st 5K kWh @ .06049			1st 5K kWh @ .06049
(demand level II)		.5/kW for kW > 30				4.5/kW for kW > 30			> 5K kWh @ .03530			> 5K kWh @ .03530
Pacific P & L's OR Sch. 41			Apr.-Nov.	Dec.-Mar.		< 50 kW @ 10/kW		0.049980	0.049980	0.049980	0.074250	0.074250
						50 < kW < 300 is 200 + 6/kW						
						Load charge is annual						
Sierra Pacific's IS-2 rate								0.04451	0.04451	0.04451	0.04451	0.04451
Salt River Proj.'s E-47 rate	$16.00		May-Oct.	Nov.-Apr.		3.45	1.30	0.05580	0.05580	0.05580	0.0419	0.0419
Tucson Elec. Pwr's GS-31			May-Oct.	Nov.-Apr.				0.05150	0.05150	0.05150	0.050208	0.050208

3.3.2.2 Illustrative Bill Comparisons for Selected Western Utilities

The impact of different rate structures can be seen more clearly by looking at the effects of different rates structures on monthly and annual costs paid by consumers of electricity. In order to accomplish this part of the analysis, representative 1999 usage patterns from actual dairy production accounts were assembled. These formed the basis for estimating the monthly and annual costs associated with the various rates shown above. Table 3.3.7 summarizes the estimated annual costs, differences, and percentage differences in annual costs associated with the various utilities' rate structures. The range of percentage differences between the various utilities is noteworthy. Annual costs associated with the rate structures of the two large California utilities can be, depending on the other utility selected, twice or three times as large.

Table 3.3.7
Comparison of Annual Costs between Various Utilities for Representative Annual Uses of Electricity

	Annual Cost ($)	Difference Between Annual Cost and Most Expensive ($)	Annual Cost as Percent of Most Expensive
Demand: < 35 kW			
(annual use equals 17,660 kWh)			
PG&E's AG 1B	$3,360	$0	100%
SCE's PA-1	$2,750	$610	82%
Tucson Elec's GS-10	$2,167	$1,193	64%
Turlock ID's FC	$1,722	$1,638	51%
Pac Pwr & Light's 25	$1,313	$2,047	39%
Modesto ID's P-3	$1,378	$1,982	41%
Wells' 0005	$1,130	$2,230	34%
Tillamook's farm	$1,071	$2,289	32%
Demand: 35kW< demand < 100 kW			
(annual use equals 39,220 kWh)			
SCE's TOU PA B	$7,240	$0	100%
PG&E's AG 4B	$6,610	$630	91%
Turlock ID's FD	$4,610	$2,630	64%
Salt River's E-47	$3,880	$3,360	54%
Wells' 0004	$2,890	$4,350	40%
Pac Pwr & Light's 41	$2,470	$4,770	34%
Surprise Valley's PA	$2,290	$4,950	32%
Sierra Pacific's IS-2	$1,750	$5,490	24%
Demand: demand > 100 kW			
(annual use equals 257,360 kWh)			
PG&E's AG 5B	$26,570	$0	100%
SCE's TOU-PA-5	$24,460	$2,110	92%
Turlock ID's FD	$17,660	$8,910	66%
Salt River's E-47	$13,840	$12,730	52%
Pac Pwr & Light's 41	$13,380	$13,190	50%
Sierra Pacific's IS-2	$11,460	$15,110	43%

Figures 3.3.3 (lower kW), 3.3.4 (mid range kW) and 3.3.5 (higher kW) graphically illustrate the results of the comparisons shown in the above table.

Figure 3.3.3

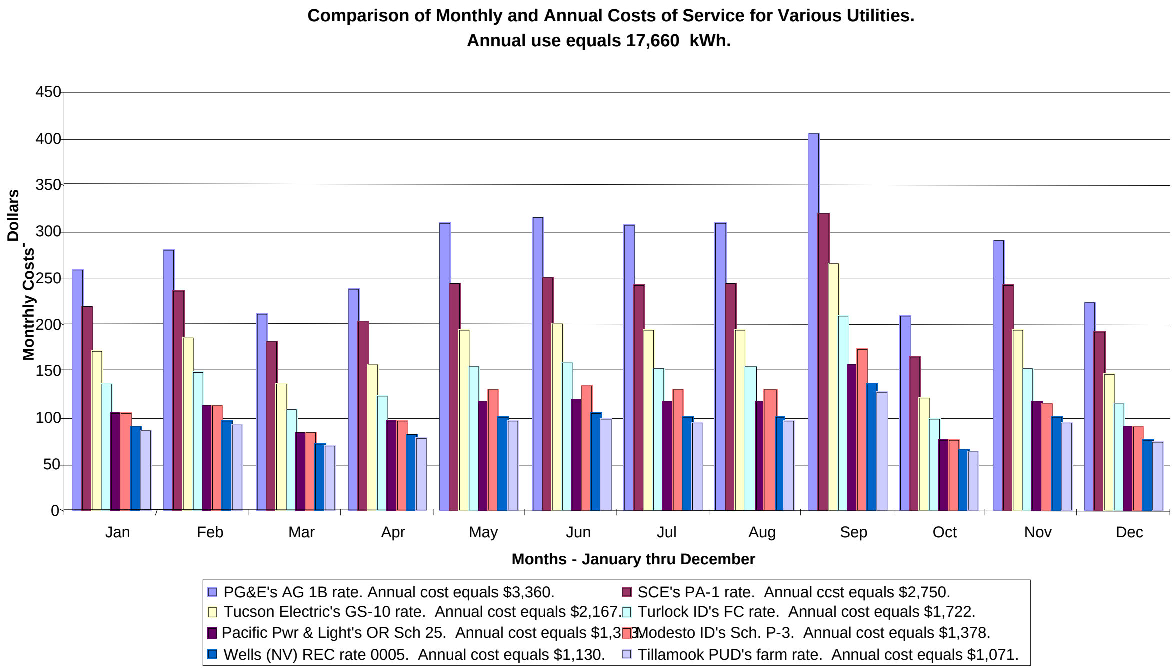


Figure 3.3.4

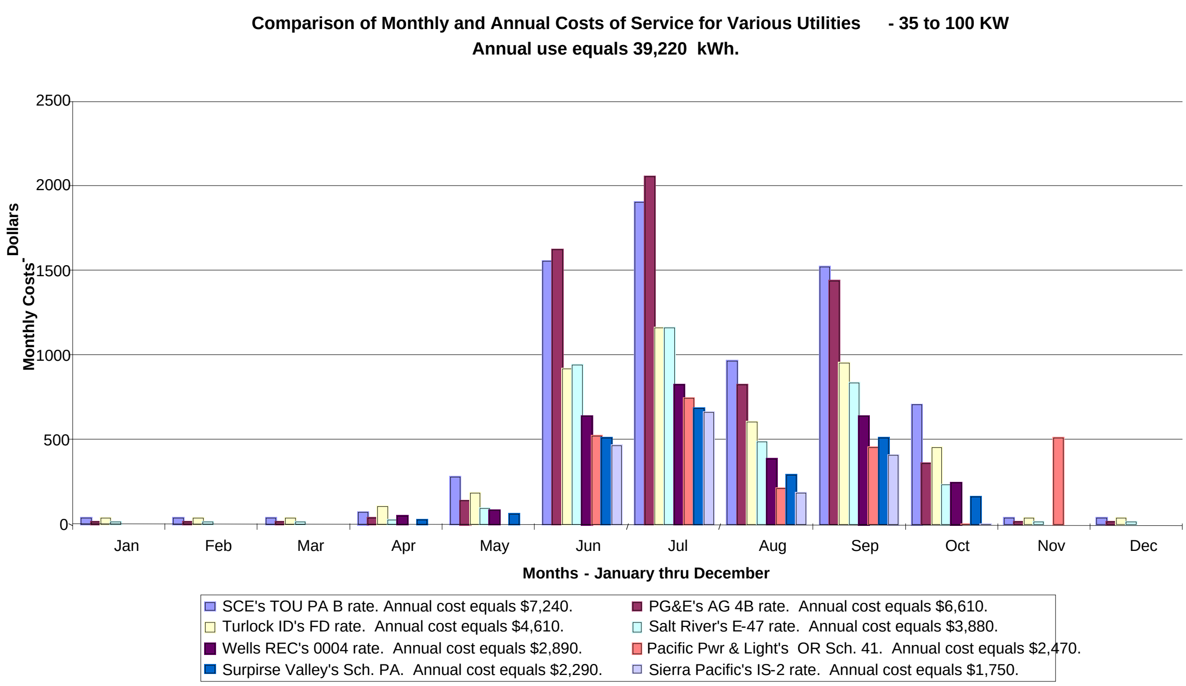
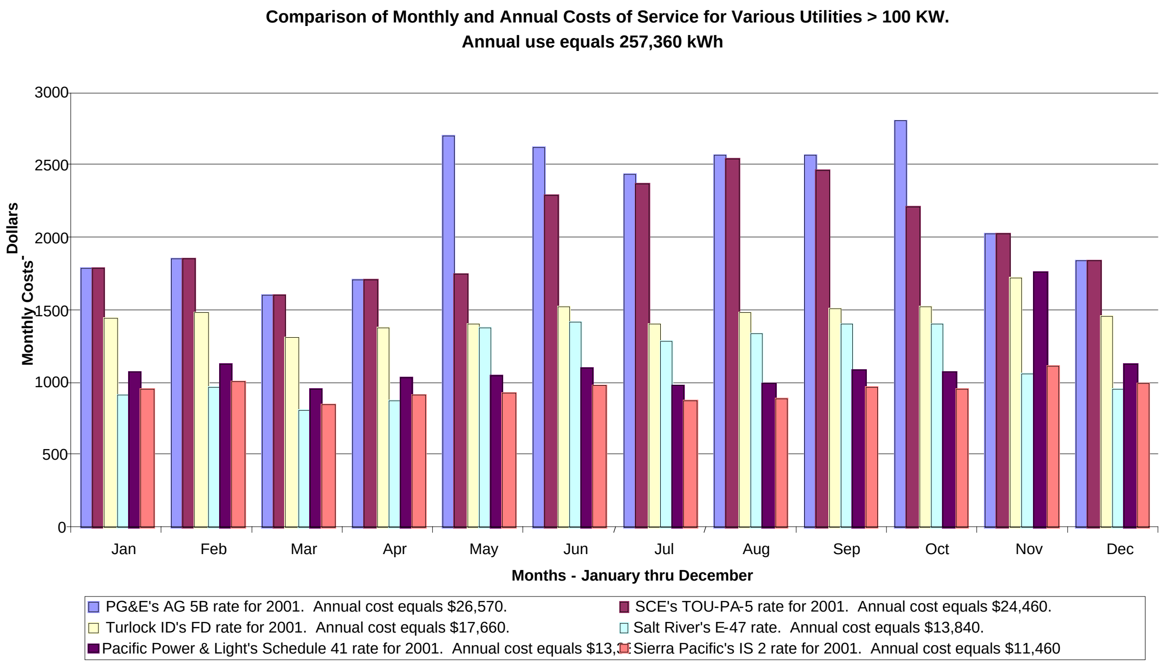


Figure 3.3.5


Comparison of Monthly and Annual Costs of Service for Various Utilities > 100 KW.
Annual use equals 257,360 kWh
Monthly Costs - Dollars
3000
2500
2000
1500
1000
500
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Months - January thru December
PG&E's AG 5B rate for 2001. Annual cost equals $26,570.
SCE's TOU-PA-5 rate for 2001. Annual cost equals $24,460.
Turlock ID's FD rate for 2001. Annual cost equals $17,660.
Salt River's E-47 rate. Annual cost equals $13,840.
Pacific Power & Light's Schedule 41 rate for 2001. Annual cost equals $13,
Sierra Pacific's IS 2 rate for 2001. Annual cost equals $11,460

Chapter 4

Electricity Restructuring and Agricultural Customers

4.1 Restructuring Options for Agricultural Customers

Restructuring is impacting both growers' operations and the water districts that supply them. Likewise, customers' relationships with these water districts can offer opportunities for energy savings in the restructured marketplace. That is, changes in power pricing and contracting can lead to new energy use patterns related to water pumping and deliveries for both farmers and districts. For example, in the face of higher electricity rates farmers may find that districts alter their surface water delivery schedules, or rely on conjunctive surface-ground water management in different ways. On the other hand, many districts, particularly irrigation districts, can provide their own electric service under state law, as well as supply water, and may approach their agricultural customers about providing such service. Many of these districts have access to low-cost federal "preference" power contracts through the Western Area Power Administration, and may be willing to sell a portion of this power to their customers. The Association of California Water Agencies has established a power-purchasing cooperative to leverage its buying power in the electricity market. The districts also may have access to federal or state water conservation and air quality funds that can be used to implement on-farm irrigation and energy management strategies that reduce energy use. Some of these options are discussed further in Chapter 1. All of these impacts and opportunities should be considered in assessing which options best suit an individual farm operation.

A number of issues could serve to prompt new opportunities for growers over the next several years. Since restructuring was launched in 1998, a large number of reforms have evolved, including changes in transmission and distribution pricing, the emergence of "onsite" or "distributed generation," and the growth of competition for "bundled services" between the utility distribution companies (UDC), municipal utility districts, and irrigation districts. Likewise, generation constraints are prompting opportunities for growers to defer, or interrupt, their electricity use in return for lower rates or direct payments. With the rate freeze scheduled to end in SCE's and PG&E's service by April 2002, these issues will become increasingly prominent to the agricultural sector.

Growers are primarily concerned with obtaining reliable electricity at reasonable and stable prices. Although agricultural diversity and the multiplicity of issues emerging from electric industry restructuring make it difficult to isolate issues that may affect all growers, a few key strategies are available to the agricultural sector in general.

4.1.1 Direct Customer Reductions

Growers can reduce their electricity costs by undertaking their own direct actions to reduce electricity consumption.

- *Energy conservation and load management can reduce both the volumetric "energy" charge and the monthly "demand" charged to growers.* Growers can change both their energy delivery systems, such as improved pump efficiency, and irrigation methods, such as moving to low-volume systems. These measures are discussed in more detail in Chapter 1.
- *Fuel switching for water pumping can entirely avoid electricity charges, but require additional capital investment.* Growers can install water pumps driven by diesel, natural gas or propane. These engines cost more up front than electric motors and have substantially shorter operating lives. However, the per energy unit operating costs are substantially lower, and this cost advantage will increase with the electric rate increases.

4.1.2 Distributed Generation (DG)

Advancing technology, combined with high electricity prices and increasing concerns about reliability, is acting to create new opportunities for on-site generation, including natural gas, biomass, solar, and wind power. In many cases, because of their location in rural areas, or adjacent to oil and gas fields, growers have unique opportunities to develop these resources, either as a dedicated on-farm source, or as part of an area-wide generating scheme. As a result, over the next few decades there may be greater opportunities for growers to turn to off-grid energy sources or switch to local power sources.

However, two issues of particular importance are emerging which could influence agricultural DG use. First, the most widespread on-site energy source for agriculture is the use of diesel- powered pumps. These engines are typically installed to generate additional power to pump groundwater during water-scarce years, or as a means to avoid high line-extension or distribution charges. However, there is an increasing possibility that agriculture will lose its current exemption from air quality rules, thereby threatening the widespread use of diesel engines for water pumping.[1] Similarly, federal, state, and regional air quality regulators are considering regulations which would require the use of "clean diesel," which could in turn necessitate retrofitting or retirement of existing diesel engines. The California Air Resources

[1]The Air Resources Board staff has been discussing a wide range of control measures to implement on mobile and stationary diesel engines, including those used for agriculture. The ARB adopted rules in 1999 that identified diesel exhaust particulates as potentially toxic substances. In addition, the San Joaquin Valley Unified Air Pollution District has focused on updating its inventory of agricultural engines and considered whether control measures are necessary for this category.

Board, among others, is currently working to develop economic alternatives to diesel use, including a state-sponsored retrofit or replacement program which would provide growers with the necessary funds to switch to cleaner burning fuels.

Second, the CPUC is currently investigating standby power rate structures (i.e., the charge imposed for periodic use of electricity).[2] Standby rate policies are developed principally in response to development and use of large-scale DG. For example, a firm or institution with its own generating capacity may have occasional need for grid power while their generator is down for scheduled or unscheduled maintenance. However, standby, in the form of connected load, reservation, or demand charges, is also used by growers with intermittent energy needs (e.g., wind machines used to prevent frost). As a result, emerging policies which either increase, or reduce, these charges are of particular importance to growers.

4.1.3 Demand Bidding and Interruptible Loads

Both the UDCs and the ISO are currently offering programs to purchase interruptible power on a short-term basis. Under these programs, electric users are paid "capacity" and "energy" payments, which are equivalent to the avoided costs saved, in return for interrupting the use of their regularly operated pumps for up to eight hours at a time. Demand bidding programs provide for the possibility of energy savings, but also may require the installation of advanced metering equipment, as well as changes in how on-farm energy use is managed through standard practices and institutional rules (e.g., at water districts). The CPUC has recently issued a decision on the load management programs offered by the UDCs in the hopes of identifying ways to increase cost-effective participation in these ventures.[3]

4.1.4 Irrigation District Competition

Before market prices exploded, certain agricultural irrigation districts that received exemptions through the electric restructuring law were able to avoid imposing the competition transition charge assessed to UDC customers to pay for "stranded assets."[4] In many areas of the

[2] R.99-10-025

[3] D.01-04-006.

[4] Up to 185 megawatts (MW) of irrigation district load is exempt from the CTC under Assembly 1890. The California Energy Commission allocated 110 MW. The following water districts received CTC exemptions through allocations from the CEC: Alpaugh Irrigation District, Belridge Water Storage District, Berrenda Mesa Water District, Cawelo Water District, Delano-Earlimart Irrigation District, Fresno Irrigation District, Kern-Tulare Water District, Laguna Irrigation District, Lower Tulare River Irrigation District, Lindsay-Strathmore Irrigation District, Modesto Irrigation District, Orange Cove Irrigation District, Rag Gulch Water District, Pixley Irrigation District, Semitropic Water Storage District, Southern San Joaquin Municipal Utility District, Terra Bella Irrigation District, Wheeler Ridge-Maricopa Water Storage District. Merced Irrigation District received the remaining 75 MW. Under restructuring legislation at least 50 percent of this exemption is to be used for agricultural pumping. In addition, loads served by members of the Southern San Joaquin Valley Power Authority and the Eastside Power Authority for

Central Valley, irrigation districts, such as Merced, Modesto, and Turlock, were actively seeking to expand their customer base, particularly for agricultural customers. In addition, electric cooperatives, such as California Electric Users Cooperative, were being developed specifically to serve agricultural needs. However, the market price run-up has now eliminated the CTC for the foreseeable future, and the exemption no longer provides a benefit to these districts' customers.

If direct access resumes, districts and co-ops will compete with the UDCs to provide low cost, reliable distribution and customer services, such as billing and metering. Although the aggregate savings associating with switching from the UDC to an alternative full- or partial-service provider may be less than anticipated under restructuring, many districts have lower distribution rates, potentially making them an attractive alternative to the UDCs over the long-term.

4.2 The Economics of Fuel Switching from Electricity to Diesel

The push to increase agricultural electricity rates that began in the 1980s[5] has lead to a revival in the use of diesel and natural-gas fueled water pumps. Economics favors the use of diesel rather than electrical motors for agricultural pumping. Farmers often will stay with electric pumps because the pumps are still in place and electric motors tend to be more reliable and require less service than diesel or natural gas engines. However, as electric pumps are replaced, diesel is likely to become more common.

This trend has two important implications. First, fewer customers will be around to cover the electric utilities' fixed costs, particularly for rural distribution systems. The resulting higher rates could push yet more agricultural customers off line. The utilities could end up with substantial amounts of "stranded" distribution system investment in these regions. Second, diesel engines tend to emit more pollutants than natural gas engines or electricity generators per unit of energy. Installing diesel engines will increase emissions and shift emissions from areas where electricity is generated to agricultural regions. As a result, air quality in agricultural regions will worsen. In setting agricultural electricity rates, the state should consider the broader range of environmental and economic policy objectives, such as clean air goals.

4.2.1 Comparative Cost Analysis - Electric Motor vs. Diesel Engines

During the most recent decade in California agriculture, irrigation systems have continued to be installed. This is especially true in regions where orchards are being planted. Well drilling continues, with greater drilling activity in drought years than in non-drought years. Statements

the purpose of pumping water are exempt from the CTC.

[5] See discussion in Chapter 3.

from installers of irrigation systems confirm that the minimum size of newly irrigated blocks of orchard land is 20 to 30 acres. Larger blocks range from 60 to 100 acres. Electric motors of greater than 50 hp (diesel engines greater than 70 hp) are the rule, rather than the exception. Ultimately, the required hp will be a function of depth to groundwater, the design pressure of the irrigation system and the desired application rate.

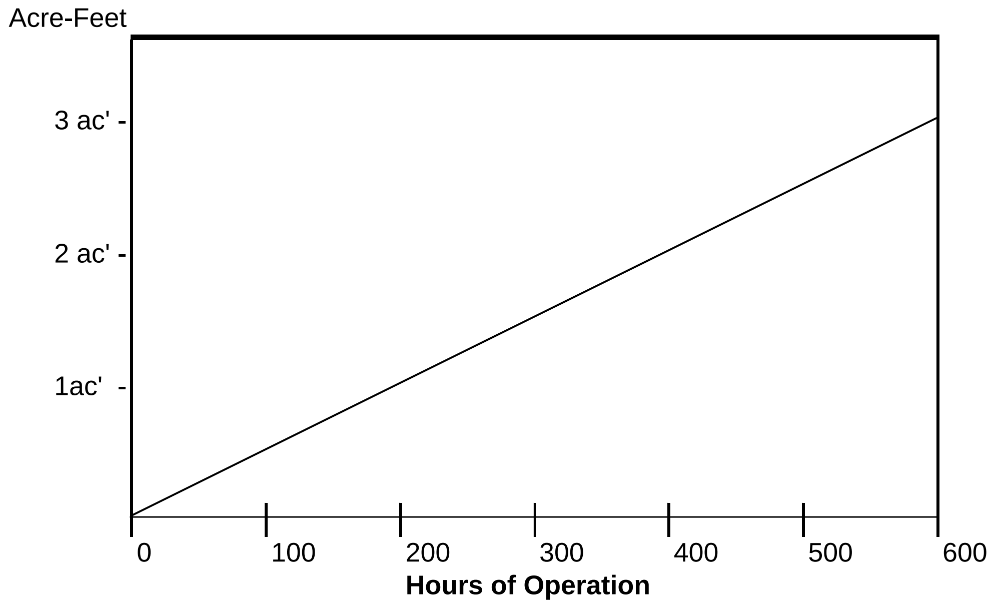
Irrigation system installers report that during the 1990s, about 90 percent of all installed irrigation systems were powered by diesel engines. Electric motors were used about 10 percent of the time. Half of this 10 percent were installations of new electric motors (including new electric service lines ("drops") and electric panels) and half were replacements of existing electric motors (not requiring a "drop," bur usually requiring a new panel).

4.2.1.1 Production Function.

The analysis begins with a representative production function (Figure 4.5.1). The production function expresses the relationship between hours of irrigation and the amount of water applied over an irrigation season. Output (acre-feet of water applied per acre per year) is shown on the vertical axis and the hours of operation are shown on the horizontal axis. The rate of water application (slope of production function) is .06 acre-inches of water per hour. In order to provide .06 acre-inches of water per hour at desired pressure, for about 70 irrigated acres, it is assumed that either a 75-hp electric motor or a 95-hp diesel engine will be used. Depth to ground water is assumed to be identical in both cases (6'), since each engine hp requirement would be similarly affected if depth to water was introduced directly into the analysis.

Figure 4.2.1

Irrigation System Production Function



1) System designed apply .06 ac" of water per acre per hour. Given that approximately 70 acres of ground is to be irrigated, either a diesel engine of about 95 hp or an electric motor of about 75 hp is required.

***4.2.1.2 Cost Functions*.**

Production functions, when the variable input is multiplied by the price per unit of the variable input, become variable cost functions. Expressing variable costs as a function of output allows showing variable cost on the vertical axis with output shown on the horizontal axis of a graph. Variable cost, in this case costs directly attributable to energy use, is then added to costs that do not vary with respect to output (fixed costs). The sum of variable cost and fixed costs is total cost of operation of the irrigation system over the range of acre-feet of water that can be applied over an irrigation season.

Fixed and variable costs of operation of diesel engine and electric motor irrigation systems are shown in Tables 4.5.1 and 4.5.2. Table 4.5.3 shows the calculation of the average hourly electric rate for large agricultural consumers used in the analysis. Note that the electricity rates shown in Table 4.5.3 are those in effect before January 1, 2001. Agricultural rates have risen at least 25 percent as of June 1, 2001.

Table 4.2.1
Diesel Engine Cost Estimates

Fixed Cost	**Cost Range**	**Mid-range Cost**	**Annual Cost**
120 hp diesel engine and gear head	$10-$14,000	$12,000	$1,700*
Annual maintenance and repair			$400
		Fixed Cost	$2,100
Variable Cost			
(hours of operation)(4.5 gph)(price per gallon)			

* Mid-range cost allocated uniformly over seven years.

Table 4.2.2
Electric Motor Cost Estimates

Fixed Cost	**Cost Range**	**Mid-range Cost**	**Annual Cost**
Electric motor and service			
75 hp electric motor	$5-$7,000	$6,000	$860*
Service installation (pole(s), wires, meter, panel, fee)	$5-$9,000	$7,000	$1,000*
Annual maintenance and repair			$200
Electric Motor and Service Fixed Cost			$2,060
Facilities Related Demand, Customer and Meter Charges			
Monthly Demand Charge ($6.55)(seasonal billing demand (kW**))			$2,295***
Monthly Customer Charge ($16)			$192
Monthly Meter Charge			$72
	Utility Fixed Cost		$2,559
	Fixed Cost		$4,619
Variable Cost			
(hours of operation)(kWh/hour)(price per kWh)			

* Mid-range cost allocated uniformly over seven years.
** 70 kW
*** Five months of operation

Table 4.2.3
Average Electricity Rate for Analysis

Type of Rate	**Percent of Time on Rate**	**Rate ($/kWh)**	**Weighted Average Rate***
Peak	17	.07947	.05149
Mid-Peak	26	.051142	
Off-Peak	57	.04283	

* Includes state tax

4.2.2 Cost Comparisons

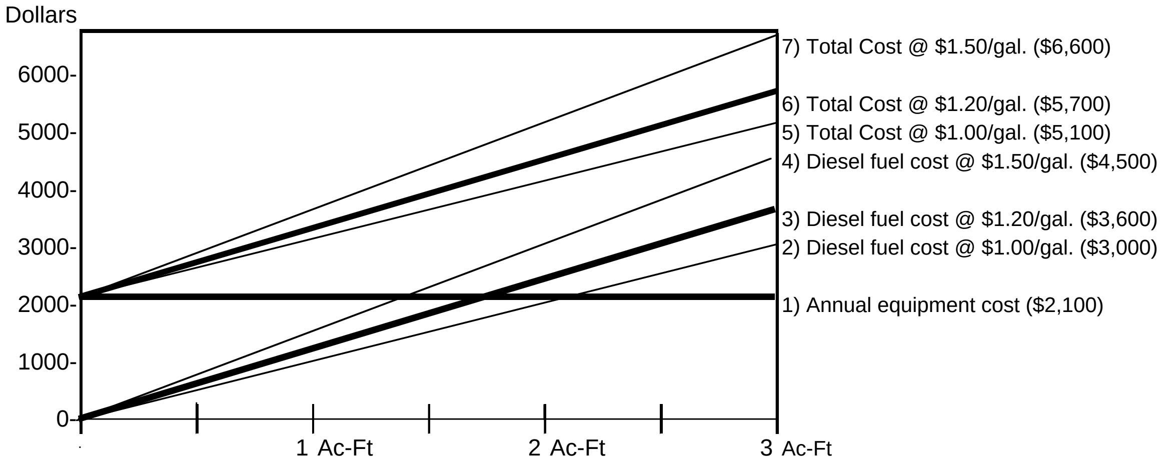
Figures 4.2.2 and 4.2.3 summarize the information contained in the above tables. Figure 4.2.4 combines information from Figures 4.2.2 and 4.2.3, and allows a direct comparison of the costs of the two irrigation systems.

4.2.2.1 Diesel Engine Costs

Figure 4.2.2 shows fixed, variable and total costs of operation of a diesel engine irrigation system over an irrigation season. The total amount of water applied per acre is shown on the horizontal axis. By varying the price per gallon of dyed diesel #2 fuel, the range of possible annual costs can be examined. If diesel fuel is priced at $1/gallon, total cost for applying 3 acre-feet of water per acre is $5,100. If the price is increased to $1.20/gallon (price paid in May 2001) and then to $1.50/gallon, the annual cost of operation increases to $5,700 and $6,600, respectively. This series of fuel prices corresponds to annual per acre irrigation costs ranging from $73 to $94.

Figure 4.2.2

Costs of Operation of Diesel Pump over Irrigation Season

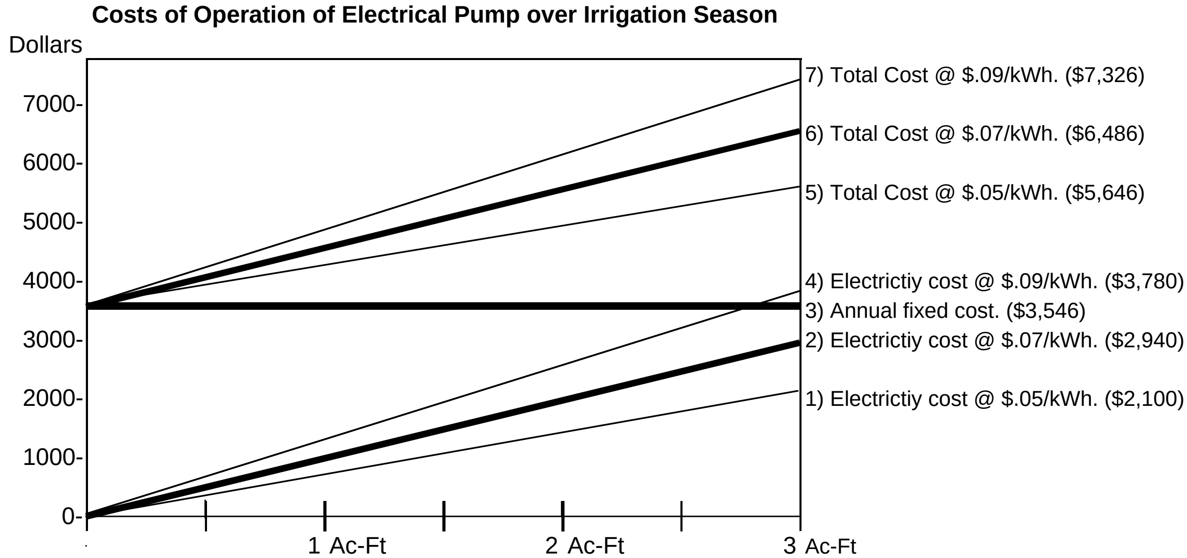


1) Annual equipment cost: Cost of diesel motor and gear head allocated evenly over seven years
2) Diesel fuel cost: number of hours of operation multiplied by gph multiplied by price of diesel
5) Sum of 1) and 3)

4.2.2.2 Electric Motor Costs

Figure 4.2.3 shows costs of operation of an electric motor irrigation system over an irrigation season. By varying the average price per kWh, the range of possible annual costs can be examined. If electricity is priced at $0.05, $0.07 and $0.09 per kWh, total annual costs for applying 3 acre-feet of water per acre range from $5,646 to $7,326 respectively. This cost range corresponds to per acre irrigation costs of $81 to $105 per acre.

Figure 4.2.3



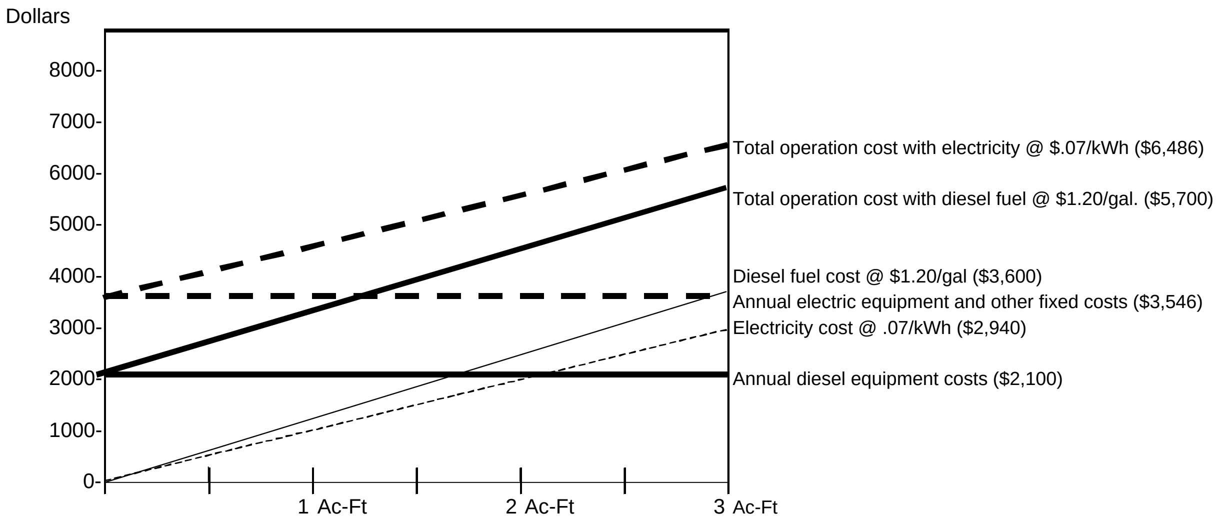
1), 2) and 4): Electricity cost: (kWh)(price/kWh)
3) Annual fixed cost.
5), 6) and 7): Sum of 3) and electricity cost

4.2.2.3 Comparative Cost Analysis

Figure 4.2.4 is constructed by "overlaying" Figure 4.2.2 on Figure 4.2.3. The figure illustrates the cost disadvantage of electric powered systems as compared with diesel fuel systems. <u>This difference has grown substantially more than shown here with the recent electricity rate increase.</u> Given a diesel price of $1.20/gallon and electric power priced at $0.07/kWh, the difference in total costs narrows over the range of applied irrigation water per acre, but the difference at 3 acre-feet remains sizeable ($786). Expressed in percentage terms, the cost of the electric powered system is 114 percent of the diesel-powered system at three acre-feet.

Figure 4.2.4

Costs of Operation of Electric and Diesel Pump Systems over Irrigation Season



Not specifically addressed above, but very important to growers, is that the use of diesel-fueled pump engines allows irrigation to occur when crop and weather conditions dictate, rather than to have to plan around significantly greater peak electricity rates and much greater peak demand charges.

Another way to compare the costs of the systems is to estimate the price of the alternate energy source that would result in equivalent total costs at three acre-feet. Given an electricity price of $0.07/kWh, diesel fuel prices would have to increase to about $1.46/gallon in order for diesel system total costs to be equal to the cost of the electric powered system at three acre-feet.

Alternatively, the figure shows that electric energy prices would have to decrease to about $0.05/kWh before total costs of both systems would be approximately equal (given a diesel price of $1.20/gallon) at three acre-feet of water.

4.2.3 Air Quality Considerations

Early in the fall of 2000, the California Environmental Protection Agency's Air Resources Board (ARB) approved a plan with the expressed goal of reducing diesel emissions by 75 percent during the next decade by requiring soot traps on nearly all of the 1.2 million diesel engines in the state. The ARB's Diesel Reduction Plan proposes a three-part approach requiring use of low-sulfur fuel, retro-fitting existing diesel engines with particulate matter filters, and a nearly 90 percent reduction of particulate matter emissions from all new diesel engines and vehicles. The plan consists of 14 segments, each of which would be phased in over the next five to ten years.

Of the estimated 1.2 million diesel engines in the state, more than one million are thought to be on-road and off-road vehicles, about 15,000 are stationary engines and about 50,000 are portable engines. Many of the stationary and portable engines are used for irrigation and other agricultural purposes. The ARB's plan includes a component requiring all diesel engines with more than 175 hp to have devices installed by 2007. New farm equipment is equipped with emission control devices, so the proposed rules apply to equipment now in use.

The overall cost for the "massive retrofitting plan" was said to be significant by the ARB staff, although exact costs would be determined as each of the 14 planned segments of the plan is developed. Diesel fuel reformulation and emission control technology made available for older engines will be critical elements of each segment. Full implementation of the ARB plan is expected in 2010.

The above not withstanding, the on-going installation of irrigation systems using diesel engines, or replacement of electric motors with diesel engines, should not be expected to slow down, especially in the next few years, for the following reasons:

- Diesel engines with less than 175 hp are exempt from the proposed rules. Diesel engines of less than 175 hp can be used to pump water and irrigate up to 80 acres of ground, if the depth to groundwater is not excessive.
- The pending stationary diesel engine rules do not apply to agriculture. Most of the diesel engines used in irrigation systems can be considered stationary.

It is expected by many growers that consideration will be given during the ARB's plan development process as to how, and how often, diesel engines are actually used in agriculture. Pump motors are operated at a constant speed and at optimal engine temperatures, thus limiting the amount of possible particulate matter discharged. Irrigation is typically done three or four times per month, for 24 to 36-hour periods, during the irrigation season. Irrigation seasons generally last five to six months, depending upon where in the state the irrigation is being done. These parameters suggest an operating year of 360 to 864 hours.

Growers who use diesel engines for irrigation purposes will remain in the position of having to modify existing engines so that the new low-sulfur fuels can be used. The modifications will be expensive, but particulate matter discharges should be reduced. It is reasonable to project that the new low-sulfur diesel fuels will be more expensive than currently available fuel. As the above cost analysis demonstrates, the price per gallon of diesel can increase substantially, given that electricity prices have risen significantly above $0.07/kWh to an average of $0.11/kWh for large agricultural customers, before growers would seriously consider using electric energy to irrigate.